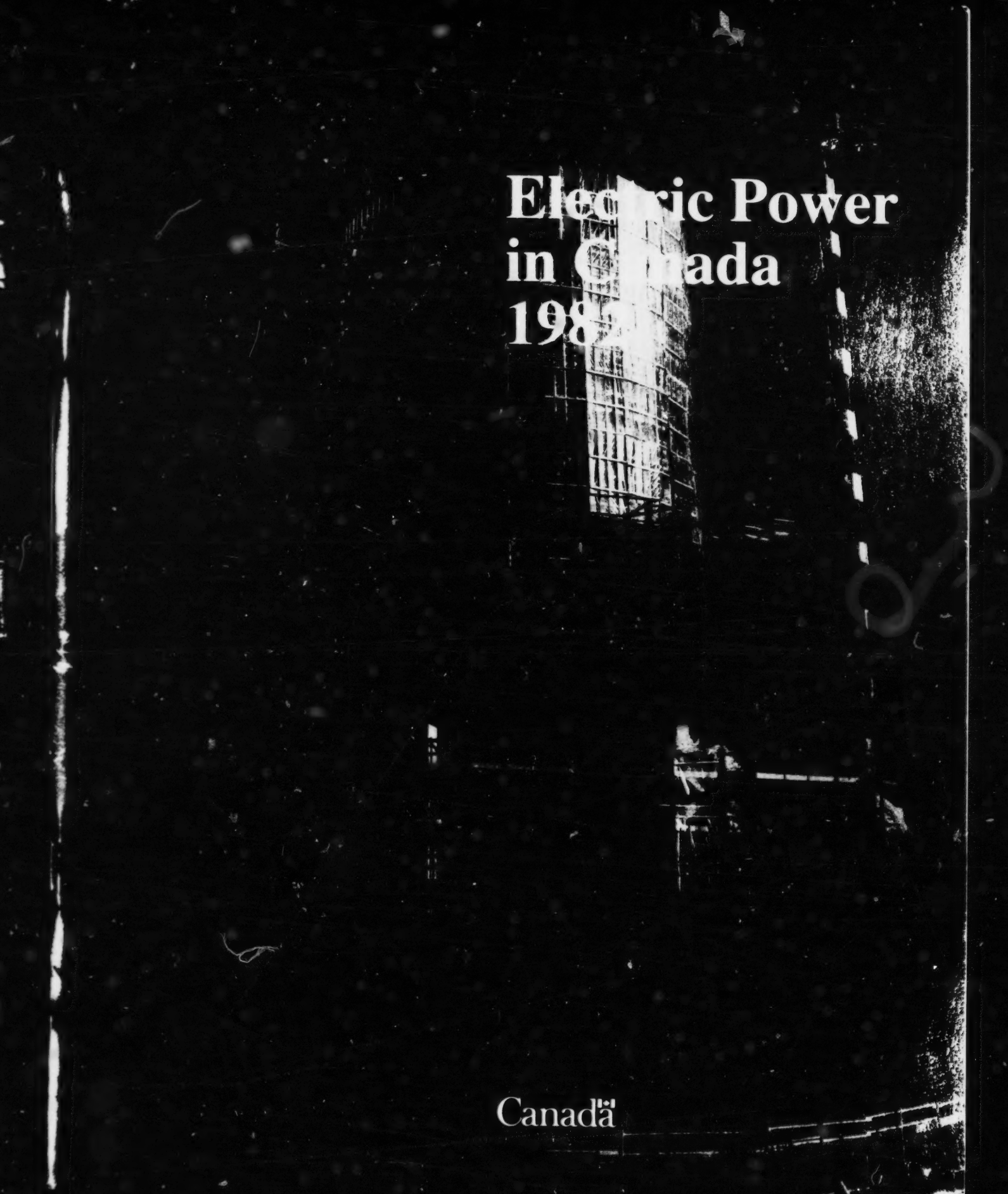

Electric Power in Canada 198

Canada

Cover:

Construction of the containment building for Ontario Hydro s Darlington nuclear plant it is designed to remove any radioactive gas from the plant

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Nova Scotia Power Corporation
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DEFINITIONS AND ABBREVIATIONS

Capacity: The rated ability of facilities to produce or deliver power at a given point in time. Installed generating capacity means the maximum amount of power that can be generated at any time.

Power: The time rate at which electric energy is made available, or consumed, typically measured in kilowatts.

Production: Generation of electric energy, typically measured in kilowatt-hours.

Consumption: Use of electric energy, typically measured in kilowatt-hours.

Power:

kW — kilowatts	
MW — megawatts =	1,000 kW
GW — gigawatts =	1,000,000 kW
TW — terawatts =	1,000,000,000 kW

Energy:

kWh — kilowatt-hours	
MWh — megawatt-hours =	1,000 kWh
GWh — gigawatt-hours =	1,000,000 kWh
TWh — terawatt-hours =	1,000,000,000 kWh

Voltage: kV — kilovolts

CONSUMPTION, PRODUCTION AND CAPACITY

Consumption

Canadian electricity demand decreased by 0.6 per cent during 1982 to an estimated 344,083 GWh (see Table 1). As in 1981, low growth in demand was related to decreased economic activity. The small decrease in electricity demand contrasts with the 4.8 per cent decrease in real Gross National Product (GNP), with which electricity demand is historically correlated. This indicates electricity use per dollar of real GNP continued its increasing trend.

Table 2 shows provincial electricity demand growth compared to the national average. The electricity demand increase of 6.6 per cent in Manitoba and 3.6 per cent in Alberta exceeded the national growth average. The increase was attributable to an abnormally cold winter in Manitoba and increased use of electric pumps in Alberta pipelines.

Since 1971 the general pattern of electricity consumption has remained the same with some sectoral variations. The industrial sector accounts for most of the electrical demand, succeeded by the residential and commercial sectors. (See Table 3).

Production

Total electricity production decreased by 1.2 per cent to 375,449 GWh in 1982. Of this, 68 per cent was from hydro, 10 per cent from nuclear and 22 per cent from conventional thermal sources. This decline reflects the 0.6 per cent decrease in domestic consumption and a 7.4 per cent decrease in net exports to the United States.

Capacity

Total installed generating capacity increased by an estimated 1,469 MW to 84,777 MW in 1982, an increase of 1.8 per cent from 1981. Hydro capacity additions totalled 608 MW, conventional thermal 181 MW and nuclear 680 MW, representing 42 per cent, 12 per cent and 46 per cent of the additions respectively. See Table 4 for details.

Table 1. Statistical Summary: Totals for Canada 1981-1982

	1982	1981	Percentage change	Table Reference*
Total Demand for Electricity (GWh)	344 083	346 333	-0.65	2
Total Generation (GWh)	375 449	380 209	-1.25	2, A4
by: hydro	255 136	263 472	-3.16	A4
nuclear	36 415	37 799	-3.66	A4
conventional thermal	83 898	78 938	6.28	A4
Total Net Exports (GWh)	31 366	33 876	-7.41	2, A5
total imports	2 848	1 496	90.37	A5
total exports	34 214	35 372	-3.27	A5
Total Capacity at December 31, (MW)'	84 777	83 308	1.76	A2
hydro	49 975	49 367	1.23	A2
nuclear	6 280	5 600	12.14	A2
conventional thermal	28 522	28 341	0.64	A2, A3
Total Net Additions to Capacity During Year (MW)	1 469	2 256	-34.88	4
hydro	608	1 679	-63.79	A6, A7
nuclear	680	—	**	A6, A7
conventional thermal	181	577	-68.63	A6, A7

' Does not reflect confidential data, which is not available by province. total confidential data for 1981: 439 MW

** The tables indicated provide data on a provincial basis*

*** Indeterminate*

The spillway at Hydro-Quebec's 2304MW LG-3 project.

A major event in 1982 was the completion of New Brunswick Power's first nuclear generating station located at Point Lepreau. The 680 MW unit, which began generating electricity in September 1982, was declared in commercial service in January, 1983.

Figure 1 gives details of capacity by energy source and region. Figure 2 indicates the type of installed capacity and electricity production by principal energy source for each province and territory. Figure 3 shows historical installed capacity mix.

Table 2. Provincial Electricity Supply and Demand (GWh)

Province	Year	Generation	Net Exports	Total Provincial Demand	1981-82 Demand Growth	1977-82 Compound Annual Growth	1972-82 Compound Annual Growth
						(%)	
Newfoundland	1982	44 264	35 777	8 487	-3.84	1.82	5.67
	1981	44 767	35 941	8 826			
Prince Edward Island	1982	35	-476	511	0.00	2.48	5.19
	1981	31	-480	511			
Nova Scotia	1982	6 581	-83	6 664	-1.54	1.62	3.61
	1981	6 576	-192	6 768			
New Brunswick	1982	8 394	-95	8 489	-4.04	1.36	4.47
	1981	8 994	148	8 846			
Quebec	1982	100 019	-17 924	117 943	-2.25	2.97	4.45
	1981	103 175	-17 481	120 656			
Ontario	1982	110 663	3 980	106 683	-0.93	1.59	3.04
	1981	111 056	3 368	107 688			
Manitoba	1982	20 779	6 413	14 366	6.56	3.30	3.48
	1981	18 384	4 902	13 482			
Saskatchewan	1982	9 843	-272	10 115	1.85	4.26	5.14
	1981	9 683	-248	9 931			
Alberta	1982	26 143	-261	26 404	3.63	8.60	7.89
	1981	25 570	90	25 479			
British Columbia	1982	47 919	4 307	43 612	0.82	2.55	3.29
	1981	51 087	7 828	43 258			
Yukon	1982	346	—	346	-10.13	-1.23	3.60
	1981	385	—	385			
Northwest Territories	1982	463	—	463	-7.77	0.35	3.05
	1981	502	—	502			
CANADA	1982	375 449	31 366	344 083	-0.65	2.78	4.04
	1981	380 209	33 876	346 333			

Table 3. Total Electricity Demand in Canada by Sector 1978-1981

	1978		1979		1980		1981	
	(GWh)	(%)	(GWh)	(%)	(GWh)	(%)	(GWh)	(%)
Residential and Farm	86 106	27	87 638	27	92 669	27	96 052	28
Commercial	68 721	22	72 384	22	73 450	22	75 709	22
Industrial	161 608	51	163 443	51	173 949	51	174 572	50
TOTAL	316 435	100	323 465	100	340 068	100	346 333	100

Source: Statistics Canada. 57-202

Figure 1

Capacity and Production by Region and Energy Source, 1982

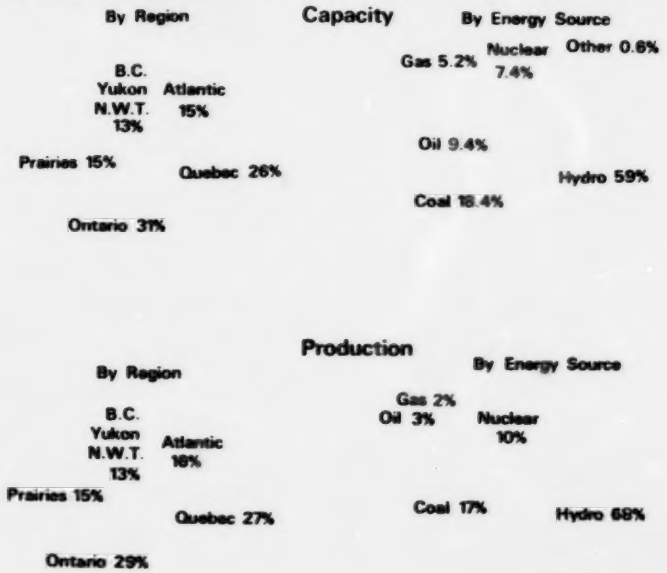


Table 4 Changes in Installed Capacity During 1982

Province	Project Name	Plant Type	Number of Units	Capacity (MW)
Additions				
Nova Scotia	Gisborne Canal	Hydro	1	3 50
New Brunswick	Point Lepreau	nuclear	1	680 00
Quebec	Beauharnois	hydro	1	46 75
	La Grande - 3	hydro	3	576 00
	Various locations	internal combustion	7	4 08
	Trenche	hydro	1	50 00
Ontario	Thunder Bay	steam (coal)	1	149 00
	Bruce	gas turbine	2	28 00
	St Mary's	hydro (Great to Lakes Power Co Ltd)	1	18 00
Northwest Territories	Various Locations	Internal combustion (Northern Canada) Power Commission	2	60
TOTAL ADDITIONS				1 555 93
Removed from Service				
Quebec	Beauharnois	hydro	1	37 30
	Various Locations	internal combustion	3	0 72
	Various Locations	hydro	4	48 88
TOTAL REMOVED				86 90
TOTAL NET ADDITIONS				1 469 03

Provincially owned utilities except where indicated

Figure 2

Installed Capacity and Electric Energy Production by Principal Fuel Type, 1982

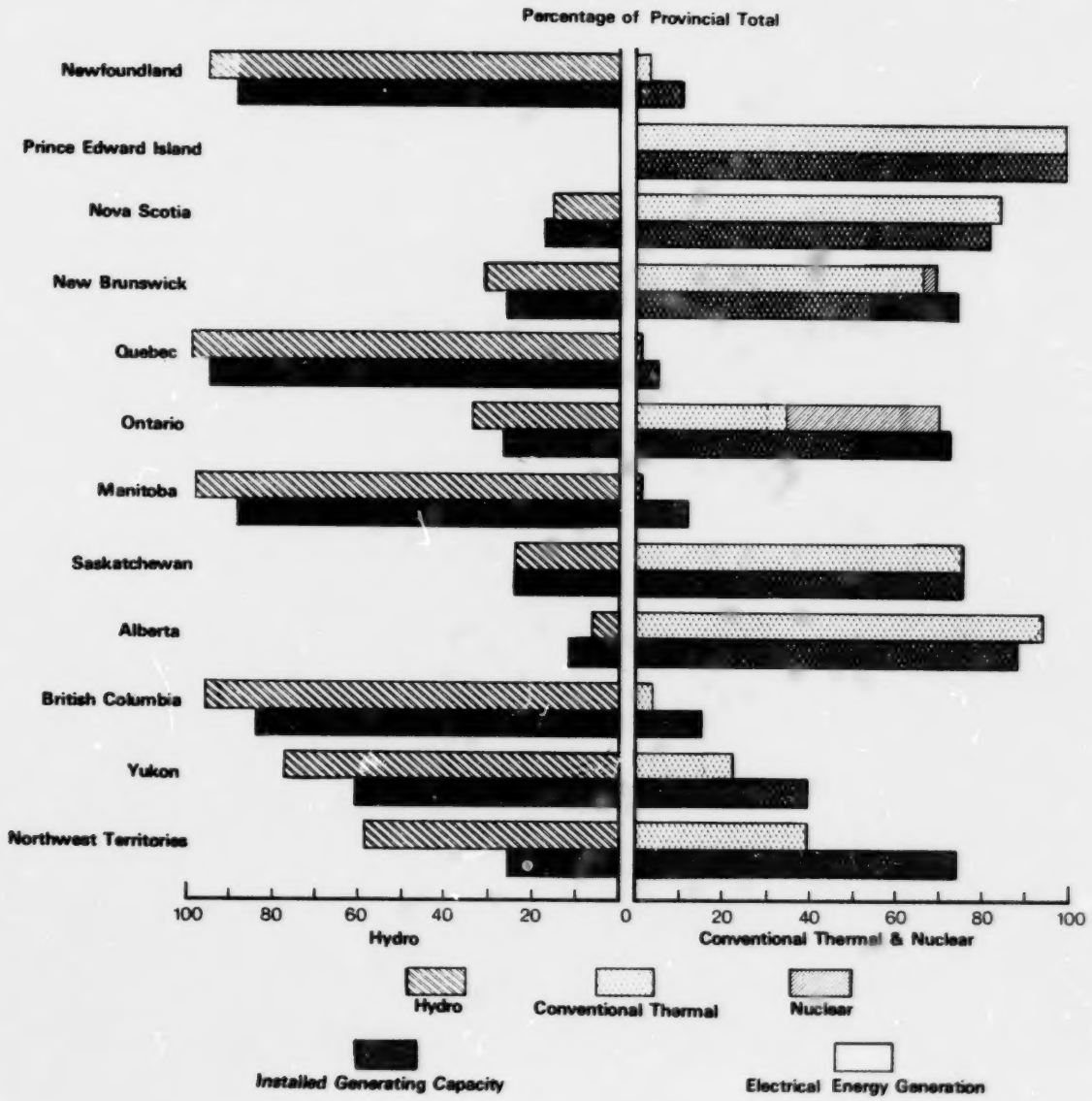
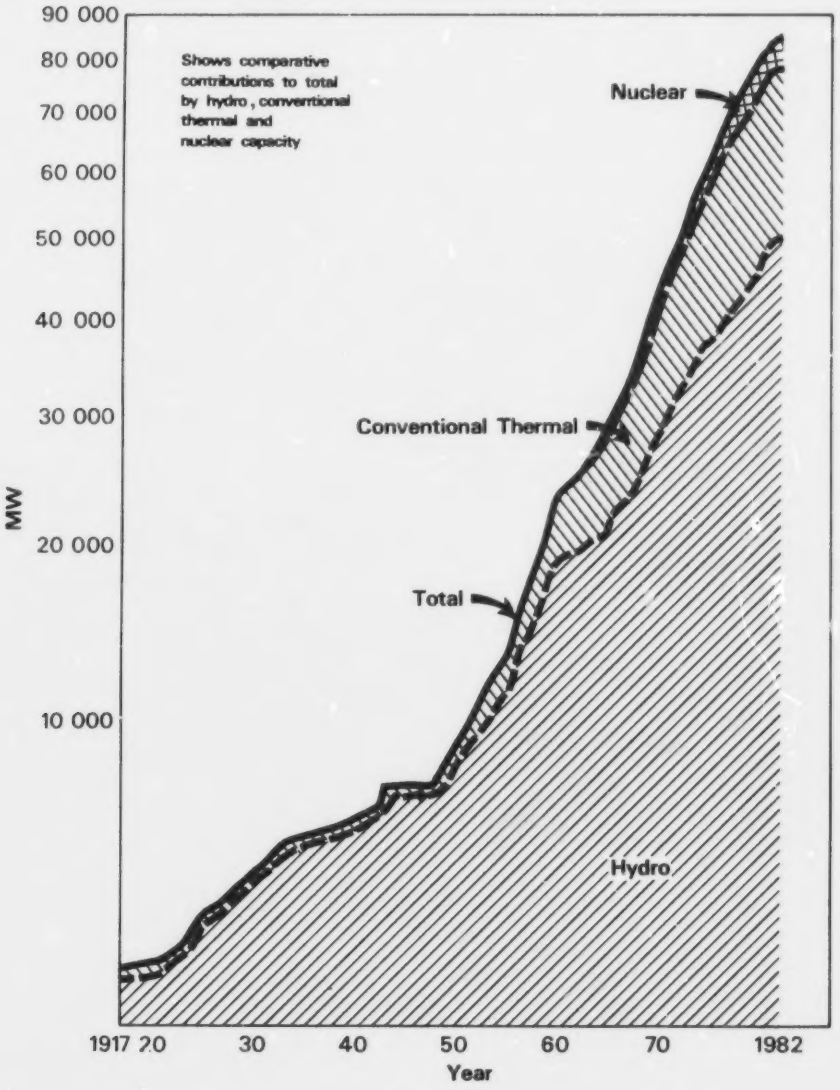


Figure 3

Historical Installed Capacity, 1917-1982



DEVELOPMENTS IN 1982

This section is a guide to the important developments in Canadian electricity supply and demand during 1982.

Federal Policy Developments

In 1982 the Government of Canada reported on progress towards the objectives of its National Energy Program. Responses to challenges were identified in the "National Energy Program Update 1982".

By 1990 the program seeks to reduce Canada's dependence on oil to 10 per cent of the energy used by the industrial, commercial and residential sectors. To reach this objective, electricity and natural gas must secure greater shares of primary energy supply. The electrical share is predicted to rise to 44 per cent by 1990; it was 33 per cent in 1975 and 39 per cent in 1982.

The Role of Electricity in the Canada Oil Substitution Program (COSP)

The Canada Oil Substitution Program (COSP) was implemented in May 1981. It provides taxable federal grants for up to 50 per cent of the conversion cost from oil to gas, electricity, or renewable energies to a maximum grant of $800 for residential space heating. Between May 1981 and December 1982, there were over 107,000 conversions from oil to electric heating, mainly to the conventional baseboard type. By comparison, there were close to 124,000 conversions to natural gas, 87,000 to wood and 5,400 to propane.

Interest is growing in new technologies such as heat pumps and electric/oil hybrid heating systems. In the latter system, electricity provides most of the requirements by heating coils installed in the warm air plenum of an oil furnace. The furnace provides the remaining heat during the coldest part of the winter.

While electricity is forecast to play an expanding role in achieving the Progam's off-oil objective, the impact will not require major changes in utility capacity expansion plans, nor significantly restrict electricity exports to the United States.

Coleson Cove Conversion

A three stage study program to consider the conversion of New Brunswick Power's 1000 MW Coleson Cove generating station from oil-firing to coal firing began in January 1981. The study is funded through the National Energy Program's Utility Off-Oil Fund. To date phases 1 and 2 of the study have been completed. A decision on commencement of the final phase of the study was delayed as New Brunswick Power and Environment New Brunswick sought agreement on acceptable air quality standards. Efforts are being made to develop a joint N.B. Power-EMR proposal to allow study work to be resumed.

Phases 1 and 2 of the study indicate favourable economic prospects for the conversion. However, it will be necessary to re-examine the assumptions used in these phases. Uncertainties regarding oil prices and the likelihood of increased hydro imports from Quebec necessitate the re-examination.

Declining electricity demand growth and the promising initial performance of the Point Lepreau I nuclear unit must also be considered. These factors would probably reduce the oil required for Coleson Cove operation and therefore limit benefits from conversion to coal.

In addition to determining possible sources of coal supply, the study considered the use of natural gas, at competitive prices, as an interim fuel. However, the limited availability of natural gas and the timing of such availability may preclude its use as an option to coal conversion.

If conversion were delayed for several years, a coal-water mixture could also be considered as a fuel. Research on coal-water mixtures is being carried out by New Brunswick Power in conjunction with EMR under the coal utilization program.

Nuclear Industry

The CANDU nuclear system, developed by Atomic Energy of Canada Limited (AECL) in conjunction with Ontario Hydro, has proven to be one of the most effective nuclear generating options in the world. Measurement is by annual capacity factor, the industry's index of performance. Ontario Hydro's eight CANDU reactors at the Bruce and Pickering Stations rank consistently among the top rated systems in the world.

Ontario has over 5,000 megawatts of nuclear generating capacity now in service and over 8,000 megawatts under construction. The first of four units of the Pickering B station achieved criticality in October. New 600 MWe CANDU units achieved criticality in 1982 at Point Lepreau in New Brunswick and Gentilly in Quebec. Over 50 per cent of the output of Point Lepreau is licensed for export to utilities in New England for several years. At the end of 1982, over 30 per cent of the plant's capacity was under contract for export.

In 1982, a 600 MWe CANDU unit went critical in Wolsung, South Korea, after a construction period of only 61 months. A fourth 600 MWe CANDU unit is expected to go into service in Argentina in 1983. Two 600 MWe CANDU units are under construction in Romania but this project was halted in 1982, due to Romania's international financial position.

Despite the success of CANDU units in Ontario and elsewhere, the Canadian nuclear manufacturing industry faces difficulty in obtaining new orders. Electricity demand has dropped in response to low economic growth at home and abroad. Existing and committed CANDUs will continue to be supported but new orders are needed to maintain the industry and to ensure the availability of new CANDUs on a competitive basis in the future.

In 1982 Canada submitted a bid to Mexico for four CANDU 600 MWe units. This was coordinated by AECL as the main CANDU marketing agency on behalf of industry, government and the electric utilities. However, Mexico decided to defer its ambitious nuclear program. Marketing activities continued in South Korea, Yugoslavia, Egypt and other countries.

Nuclear Industry Review

The Department of Energy, Mines and Resources began a review of the Canadian nuclear industry in 1980 at the request of the Prime Minister. In August, 1981, a series of background papers was released on all aspects of the industry by the Minister of Energy, Mines and Resources. The Nuclear Industry Review was released in August 1982.

The Review focuses on the present and forecast economic situation of the Canadian nuclear industry as it faces decreased demand growth due largely to the international recession. Surplus generating capacity exists in most provinces, therefore no nuclear capacity additions beyond existing utility expansion plans are foreseen for the next decade. International competition for reactor sales has increased as reactor suppliers try to preserve their nuclear industries in a reduced market place.

Increased capacity requirements are forecast for the 1990's. Canada's nuclear generating system, based on Canadian technology and abundant Canadian uranium resources is expected to be a preferred source for capacity expansion. The Canadian government recognizes the benefits to be derived from CANDU as a competitive energy option. Policy alternatives outlined in the Nuclear Industry Review would ensure its preservation.

The Government of Canada indicated its support for the nuclear industry in the National Energy Program Update released in May, 1982. In particular, the government will consider support for future nuclear plants, including those built initially to serve the export market.

A second CANDU unit at Point Lepreau is being considered but the project will be pursued only if markets are available on a fully commerical basis. Some federal government financial guarantees may be appropriate.

Provincial Policy Developments/Issues

Hybrid Heating Program – Quebec

In 1982 the declining rate of increase in electricity demand in the province caused Hydro-Québec to call for a six year deferral of construction of new generation plants. Hydro- Québec will combine reduced capital spending with an aggressive approach to marketing electricity within and outside the province, for the period extending from 1982 to 1985.

To promote in-province sales, Hydro-Québec introduced a program to subsidize installation of electric hybrid heating systems in single family dwellings. Electric hybrid heating systems are dual energy heating systems based principally on electricity with a secondary source of heat (normally oil).

In a hybrid system, both heating systems are controlled by an outdoor temperature sensor. At temperatures above a predetermined level, space heating requirements are met by electricity. Below this level, the device triggers the secondary heating mode (e.g. oil). Hybrid heating systems provide a simple method of using oil economically for peak seasonal space heating purposes with electricity for remaining energy requirements.

Homeowners converting to hybrid heating systems may apply to Hydro-Québec for a $650 grant. The grant is available to the first 100,000 eligible applicants until the end of 1983. It is intended for systems principally based on electricity in conjunction with a secondary source of heat other than natural gas. The grant will be reduced to $500 in 1984. During 1983 the program may be extended to owners and tenants of multiple-unit residential dwellings. Customers converting from oil heating systems will also be eligible to receive a federal grant of up to $800 under the Canada Oil Substitution Program.

A second program, directed at the industrial sector, provides incentives for conversion from heavy oil to electric boilers. Similar programs are being developed for multi-family residential buildings and commercial installations.

Report of the Royal Commission on the Cost of Electric Power to Residents of Prince Edward Island

In July, 1981, Maritime Electric Company Ltd. applied to the P.E.I. Public Utilities Commission for a 21.4 per cent increase to its basic rates. In October 1981, an initial order was issued by the Commission granting an 18 per cent increase to the rates. A final order granting an additional three percent was issued in November.

In response to public reaction to the substantial rate increases and concern over future increases, the provincial government commissioned an inquiry into the costs of electric power in December 1981.

The Commission, headed by Melvin McQuaid QC, examined the problems of costly energy supplies and capital constraints. It explored the opportunities available to the provincial government and the utility.

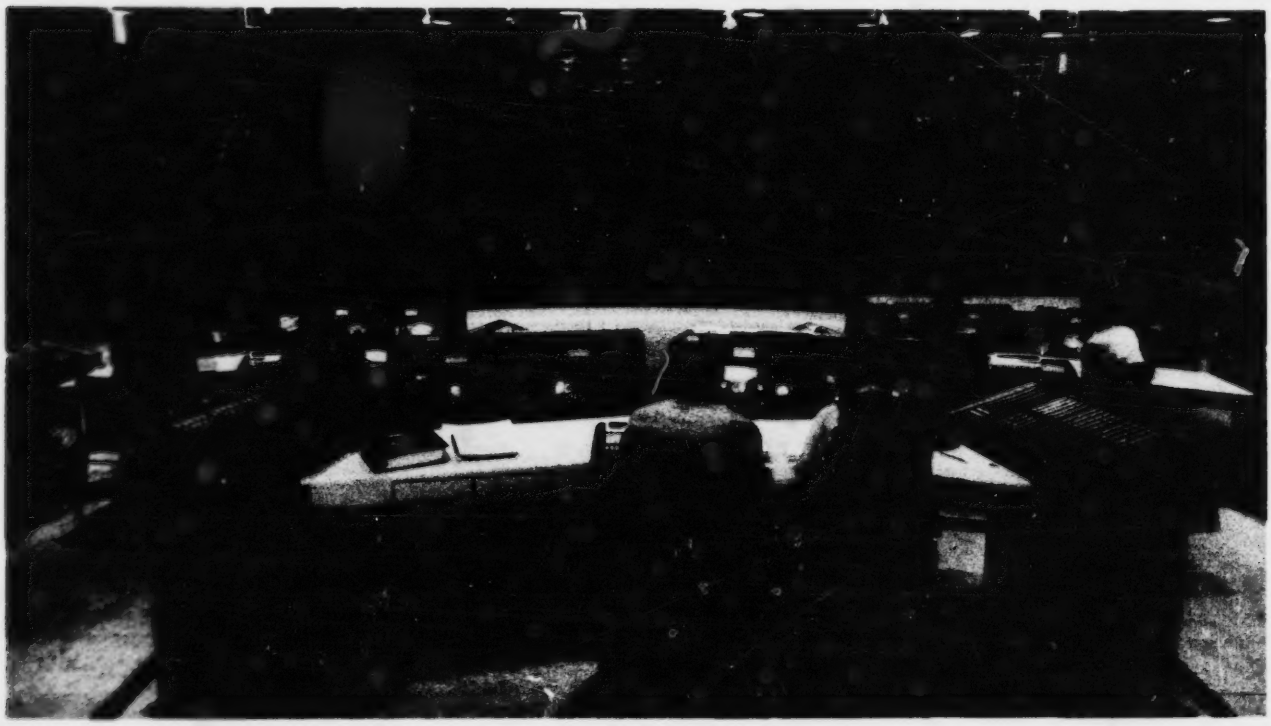
The report of the inquiry findings was released in September 1982. It contains criticisms of the investor-owned utility, Maritime Electric Company Limited. However, these criticisms are not linked to evidence that Maritime Electric acted inadvisably and the Commissioner concluded that the Company is "organized to run efficiently and is effectively managed".

The report makes few proposals for cost reduction beyond seeking federal subsidy and renegotiation of power purchase contracts with neighbouring utilities. Consultant studies have been undertaken to examine further options available to Prince Edward Island.

Newfoundland – Quebec Dispute: Churchill Falls

In 1969 Hydro-Québec signed a contract to purchase approximately 90 per cent of the output of the 5225 MW Churchill Falls hydro electric plant in Newfoundland until 2041, at a price between $2 and $3 per megawatthour. This price is less than one tenth of what it now costs to develop additional capacity.

It should be noted that Hydro-Québec could have built hydro facilities in Quebec as an alternative to purchasing electricity from Churchill Falls. These facilities would have provided the province with power at comparable cost and with similar immunity to inflation effects.



A view of the new Hydro-Quebec transmission line control centre inaugurated in Montreal in October 1982.

The Churchill Falls dispute is based on two fundamental elements: first, Newfoundland wants access to additional energy from Churchill Falls at the same price that Quebec pays. Secondly, Newfoundland wants Quebec to pay a higher price for energy from Churchill Falls, to reflect the increased value of alternate energy sources since completion of the plant in the early 1970's.

In 1976, Newfoundland began legal action to obtain 800 MW from the 5225 MW plant in addition to the 300 MW to which it is entitled by the power contract.

Newfoundland will complete development of major economic hydro sites on the island by 1985. Any major additional capacity will come from fossil-fired plants on the island or development of additional hydro plants in Labrador.

Delays in court proceedings frustrated Newfoundland's attempts to obtain additional energy from Churchill Falls. In 1980, the Newfoundland House of Assembly passed legislation which, if proclaimed, would revoke the water license for Churchill Falls, thereby expropriating the plant.

There are actions before the Courts on three separate issues:
(a) Action in the Newfoundland courts to establish Newfoundland's right to recall 800 MW from the existing Churchill Falls contract. The principle asserted by Newfoundland could, if successful, extend in stages to the entire output of Churchill Falls and eventually jeopardize all Hydro-Québec's contract rights to Churchill Falls production. A decision was rendered in June, 1983. The Newfoundland Supreme Court ruled that Newfoundland does not have the right to recall the 800 MW and that the province can only receive power surplus to Churchill Falls (Labrador) Corporation Ltd.'s commitment under the contract. The decision will be appealed.

(b) Action in the Quebec Courts to establish that recall, if successful, would be a breach of contract by Churchill Falls permitting the contract to be rendered null and void and thereby allowing Hydro-Québec to pursue a claim for damages. The Supreme Court of Canada recently decided that Hydro-Québec may proceed with its request for the Quebec Courts' interpretion of the contract but it can not bring the Government of Newfoundland before the Quebec Courts. The hearing in the Superior Court of Quebec began on March 21, 1983.

(c) Action in the Supreme Court of Canada to establish the validity of the Water Rights Reversion Act under which the Newfoundland House of Assembly proposes to annul the water licence upon which the Churchill Falls power contract is based.

The Newfoundland Supreme Court of Appeal declared on March 5, 1982 the Act constitutionally valid and within the jurisdiction of the provincial legislature. This judgement was appealed to the Supreme Court of Canada by Hydro Québec.

The federal government filed a factum with the Supreme Court of Canada on September 17, 1982 stating that the legislation is directed to an extra-provincial undertaking and consequently serves to "extinguish rights and liabilities outside the Province of Newfoundland". The factum concluded that the statute is beyond the powers of the Newfoundland legislature. The Supreme Court heard arguments on the case in October, 1982. A decision is expected in 1983.

The federal government is encouraging both provinces to reach a negotiated settlement.

CANADA-UNITED STATES ELECTRICITY TRADE

Electricity trade between Canada and the United States dates back to the early 20th century. For most of this period, net exports (i.e. exports net of imports) were insignificant in both directions. Since the early 1970's however, Canada's net exports to the United States have increased in volume and revenue so derived is a significant element in Canada's balance of payments (Table 5).

In 1982, electricity net exports produced revenue of $1.1 billion, accounting for 18 per cent of our international energy trade balance and 11 per cent of our merchandise trade balance with the United States.

One of the principal reasons for increases in net electricity exports to the United States is the difference in the source of generation in the two countries. Surplus Canadian power, approximately 60 per cent hydro-based, is used to displace costly United States oil-fired generation and other fossil-fuel generation.

This displacement has occurred mainly in the northeastern states. Exports to New York come from hydro generation in Quebec and coal-fired generation in Ontario. Oil-fired and nuclear generation in New Brunswick is exported to New England. Manitoba hydro-based exports displace coal-fired generation in the United States mid-west. Hydro-based exports from British Columbia reduce gas-and oil-fired generation on the United States west coast.

Table 5. Annual Exports and Imports of Electric Energy

Year	Net Canadian Generation (GWh) (1)	Exports of Canadian Generation (GWh)	Exports of Canadian Generation % of (1)	Imports of U.S. Generation (GWh)	Imports of U.S. Generation % of (1)	Net Quantity of Exports (GWh)	Net Value of Exports ($000)
1959	104 671	4 593	4.4	512	0.5	4 081	13 008
1960	114 378	5 494	4.8	357	0.3	5 137	13 888
1961	113 713	4 180	3.7	1 394	1.2	2 786	12 592
1962	117 469	4 034	3.4	2 779	2.4	1 255	13 891
1963	122 238	3 624	3.0	2 884	2.4	740	4 433
1964	134 987	4 185	3.1	3 121	2.3	1 064	5 658
1965	144 274	3 570	2.5	3 575	2.5	-5	-1 836
1966	158 135	4 310	2.7	3 057	1.9	1 253	5 970
1967	165 625	4 066	2.4	4 142	2.5	-76	-6 196
1968	176 378	3 646	2.1	4 129	2.3	-483	-2 725
1969	191 102	4 688	2.5	3 333	1.7	1 355	10 198
1970	204 723	5 631	2.8	3 245	1.6	2 386	23 445
1971	216 472	6 985	3.2	3 378	1.6	3 607	38 208
1972	240 213	10 379	4.3	2 381	1.0	7 998	61 590
1973	263 335	16 879	6.4	2 249	0.8	14 630	108 633
1974	280 256	15 399	5.5	2 441	0.9	12 958	168 320
1975	273 392	11 375	4.2	4 174	1.5	7 201	102 019
1976	294 043	12 804	4.4	3 590	1.2	9 214	167 200
1977	317 196	19 957	6.3	2 690	0.8	17 267	406 138
1978	335 641	21 602	6.4	2 092	0.6	19 510	476 791
1979	352 304	31 378	8.9	1 792	0.5	29 586	737 802
1980	367 306	30 176	8.2	2 939	0.8	27 237	790 640
1981	378 531	35 372	9.3	1 497	0.4	33 876	1 138 250
1982	375 449	34 214	9.1	2 848	0.8	31 370	1 100 489

Source: National Energy Board

1. Early Trade in Electricity

The contracts now governing the sale and exchange of electric power between Canada and the United States reflect the experience of more than eighty years.

During the early development stages of the Canadian electric power industry, private enterprises were involved in construction of hydroelectric, steam and diesel generating plants. The Niagara River was an obvious location for early hydroelectric development. Its situation on the United States/ Canadian border made it logical for the developers to look to the United States for sales.

At first there was no market in Canada for the output from these facilities. Consequently, most of the electricity generated in the Niagara region was exported under long-term contracts to the United States by means of aerial cables stretching across the Niagara River and via transmission lines hung under the Rainbow Bridge at Niagara Falls, New York. The first transmission line across the border was a 12kV circuit built at Niagara Falls in 1901.

Early export agreements were made between affiliated corporations operating on either side of the border. However the United States also represented an attractive market for non-affiliated companies. In 1904 Ontario Power agreed to deliver 46,000 kW of firm power over a period of 46 years to an American public utility operating in Buffalo.

Ontario was not the only province exporting electricity during the first part of the 1900's. International trade between Quebec and Vermont dates back to 1914 and trade between New Brunswick and Maine has a long history of co-operative production and marketing.

Historically, Canadian hydroelectric generation and transmission facilities were developed in advance of domestic demand. Differences in geography, demography, resource availability and seasonal diversity largely account for the early development of electricity exchanges between Canada and the United States.

Export sales under long-term contracts with American utilities provided funds to support Canadian hydroelectric development. However there was concern that this approach would eventually retard economic development and cause energy resources to be alienated from Canadians.

2. Evolution of Canadian Export Policy

Federal and provincial legislation resulted from the public demand that Canadian hydroelectric resources be reserved for Canadians. As early as 1903, several Ontario municipalities which owned local electricity distribution systems were considering constructing transmission systems. These would provide interconnection between generating facilities at Niagara Falls and municipal load centres. The provincial government recognized the need for a central authority providing administrative support to the municipalities. This authority would preserve Canadian resources by developing energy supply systems for markets within the province.

The Hydro Electric Power Commission of Ontario was created through the Ross Act of 1903. It authorized the utility to enter into bulk contracts and to develop, own and operate an interconnected provincial transmission system.

At first, there was opposition to the Commission from investor-owned utilities who saw the entrepreneurial right to export being eroded through regulation. By 1910 however, the first transmission line was completed to deliver power from Niagara Falls to seven Ontario municipalities.

Efforts to preserve hydroelectric resources were also supported at the federal level. In 1907, the Electricity and Fluid Exportation Act was passed to regulate the export of electric power and natural gas.

The legislation radically changed the character of exports by introducing a number of conditions which had to be met to the satisfaction of the Governor-in-Council.

Under the Act each export contract required a license stating the maximum quantity permitted. The licenses had to be renewed each year. Moreover, the Act stipulated that licensees could export power only in excess of Canadian needs. The price charged by the licensee had to be equal to, or greater than the price charged to Canadians under "similar conditions of sale".

The Act also established a reporting mechanism for monitoring exports. The licensee was required to submit monthly reports to the Minister of Trade and Commerce on domestic sales, production, and export sales.

An export duty not exceeding $10 per annum/horsepower was permitted on export sales. Pursuant to Order in Council P.C. 397 (March 16, 1925), the duty was established to be $2.00 per annum/horsepower. Exports were subject to this duty until 1963.

The duty was intended to make the Canadian market more attractive to power producers at Niagara. It gave notice that the government could make the export market uneconomical. Similarly, the one-year license was a reminder to exporters that permission was not to be taken for granted. American utilities could therefore not rely on Canadian electricity production to meet their base load demand.

The Electricity and Fluid Exportation Act remained unchanged until 1957. The Canadian Government then realized that local industrial requirements had to be ensured before authorizing export licenses. There was some feeling that Canada's jurisdictional responsibilities would be better served through a new organization, outside of the Department of Trade and Commerce.

In 1958 and 1959 the Borden Commission on energy recommended the establishment of a National Energy Board (NEB) with enabling legislation to replace the Electricity and Fluids Exportation Act of 1907. In 1959, Parliament enacted the National Energy Board Act and repealed the original Exportation Act of 1907.

The first major statement of a National Power Policy was announced in 1963 by the Honourable Mitchell Sharp, then Minister of Trade and Commerce. This statement reversed the restrictive policy which the government had adopted since 1907 while maintaining adequate protection for Canadian resources.

The policy encouraged development of large low-cost power resources and interconnection of systems within Canada. It promoted exports and interconnections between Canada and the United States.

Early development of remote Canadian power sources initially for export was introduced. However, the export contract must provide economic supply options for Canadian needs. The policy defined the following five areas where favourable consideration would be given to exports:

- provision of standby service for emergencies, thereby reducing reserve generating capacity required by utilities;
- economy exchanges between plants;
- sales of surplus interruptible energy;
- diversity exchanges. Since Canada's peak power demand season is winter and the United States experiences its peak demand in summer, power and energy supplied by Canada in summer can be returned by the United States in winter;
- sales of firm power for limited periods which would allow "step by step construction of the most economical generating facilities on either side of the border".[1]

In addition the policy endorsed exports of electricity to border areas in the United States which, for reasons of geography, were more economically supplied by Canada. This has been the practice since the earliest days of electricity exchanges.

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[1]Statement of National Power Policy by the Honourable Mitchell Sharp, Minister of Trade and Commerce, October 8, 1963.

In late 1977, the United States proposed a joint study on Canada-United States co-operation on bulk electricity exchanges. In 1979, a report entitled "Canada/United States Electricity Exchanges" concluded that significant opportunities exist for increased international exchanges in all border regions. These would result in mutual benefits, including reduced oil consumption and increased system reliability. Among the recommendations were the following:

- increased communication and liaison among regulatory agencies and between agencies and utilities;
- clear statements of government policies and guidelines on the regulatory processes for international exchanges;
- export pricing policies to maximize opportunities and benefits;
- development of public information programs explaining the benefits to be gained from international electricity exchanges.

In 1982, the Government of Canada supported the expansion of the export market for electricity through the National Energy Program (NEP) Update. The program endorses prebuilding capacity in advance of domestic demand assuming "an equitable distribution of the risks and financial burdens between buyers and sellers and satisfaction of appropriate environmental standards."[2]

This type of expansion program could be financed out of export earnings and it is consistent with the 1963 policy statement. The government has indicated willingness through the NEP Update to consider support for construction of nuclear plants built initially to serve the export market. The Government of Canada would provide financial support for an arrangement with United States utilities allowing Lepreau 2 to be built in the near future, subject to the general criteria of the Government of Canada with respect to price and risk-sharing.

The Canadian Government position on electricity exports was explained further in 1982. Speaking to United States audiences, the Minister of Energy, Mines and Resources and the Minister of State for Mines reiterated Canada's support for continued electricity trade and increased exports. They stressed the reliability of Canadian electricity exports and Canada's desire to promote trade between the countries.

3. Institutional Environment

Canadian and American institutional structures have influenced the evolution of electricity exchanges. There are significant differences with respect to utility ownership, operating procedures and regulation. Despite the differences, there exists a large degree of cooperation through the North American Electric Reliability Council (NERC), an organization which coordinates planning and reliability design of the North American systems. Its members include Canadian utilities having interconnections with the United States.

3.1 Government Jurisdiction – Canada

Sections 91 and 92 of Canada's Constitution outline the jurisdictional powers of the federal and provincial levels of government.

Each province has jurisdiction over the natural resources located within its boundaries. The production and distribution of electricity within a province are administered provincially.

Federal jurisdiction over international and interprovincial trade was established under Section 91 of the Constitution. It was originally outlined in the Electricity and Fluids Exportation Act of 1907 and carried forward through the National Energy Board Act (1959).

Federal jusisdiction over electricity was limited to the regulation of international power lines and licensing exports. In exercising its mandate, the National Energy Board ensures each application to export power meets the following criteria:

- exports must be surplus to foreseeable Canadian needs;
- the price charged by the licensee must be just and reasonable ("in the public interest");
- the maximum term of the license must be no longer than 25 years (most licenses are issued for periods ranging between 5 and 10 years corresponding to the request of applicants).

In assessing the first criterion, neighbouring utilities must be given first right of refusal for any proposed exports under the same terms and conditions.

The Board's consideration of "public interest" may include such issues as economic and environmental impact, employment opportunities and balance of payment considerations.

The National Energy Board has certain tests to determine if the price charged for exports meets the "public interest". First, the price must not be less than the cost of producing the energy. Second, the price must not be less than the cost of comparable service to Canadians. Finally, the price must not be materially less than the cheapest alternative available to the United States purchaser.

These tests are interpreted with some flexibility. The importer should be provided with some incentive to reflect differences between local and imported supplies. Pricing policy also recognizes cases of American purchasers with investment in Canadian generation or transmission facilities for import purposes.

[2] *National Energy Program Update 1982*, Energy Mines and Resources, 1982.

In February 1983, the power of the NEB was extended. Any facility constructed and operated for the purpose of interprovincial transfer of electricity may be designated by the Governor-in-Council as subject to the NEB Act's provisions for international power lines. In addition the NEB may authorize land expropriation for international and other designated lines. This is consistent with its existing powers for pipelines.

The provinces have primary jurisdiction over environmental issues. However, both levels of government may rely on the NEB for an environmental review at the detailed application stage. In cases where a federal activity, money or property is involved the Federal Environmental Assessment and Review Process (EARP) will apply at the project planning stage. This may then lead to a public review. It should be noted that few, if any, export projects will have federal funding or affect federal lands.

The federal government requires compliance with the Navigable Waters Act in applications for certificates to construct transmission lines across navigable bodies of water. Separate authorization must be obtained from the Department of Transport and compliance shown with the Fisheries Act.

Apart from shared environmental responsibilities, which to date have not proven difficult to manage, jurisdiction between federal and provincial levels of government is well defined. The National Energy Board recommends that exporting utilities consult with the Board prior to submitting an application. This provides utilities with an understanding of regulatory policies and procedures, thereby reducing application processing time.

3.1.1 Canadian Licensing Procedures

Every applicant requesting an export license must provide the NEB with the information described in the National Energy Board Act Part VI regulations.

In considering applications, the Board distinguishes between proposed exports of firm power and interruptible energy. In the case of firm power, a more detailed review is required because firm power is "intended to be available at all times during a period covered by an agreement."[3]

Applications to the Board usually require a public hearing, at which time evidence for or arguments against an application may be presented. The hearing is held before a panel of three Board members. A decision is handed down in the form of a "Reasons for Decision" document on the basis of the testimony presented. This report states the decision and the rationale behind it. It describes the application, summarizes all of the evidence and defines the conditions applicable to the certificate of public convenience or export license.

The Board has developed guidelines for considering certification of international power lines. These include the following:

- availability of power for the line;
- identification of markets;
- economic feasibility of the line;
- financing considerations;
- public interest;
- environmental impact of the facility.

Where the federal Environmental Assessment and Review Process (EARP) is required, proposed projects must be screened in the early planning phase to determine significant environmental effects. If, in the opinion of the Minister of the proponent department, the project will have significant environmental effects, it must be referred to the Minister of the Environment for a public review by an independent Environmental Assessment Panel. The Panel review is usually conducted early in the project planning stage and is completed before firm decisions are taken.

Projects are assessed also on the basis of an environmental impact statement and a hearing process. A detailed report with recommendations is submitted to the Minister of the Environment. Decisions are reached in consultation with the Minister of the department initiating the referral. However, final decisions are deferred until the NEB or other regulatory authority deals with the detailed application.

There are specific conditions under which the National Energy Board may waive the requirements for a public hearing and government approval. The Board may authorize exports where the export is small, i.e. less than 50 MW or 250 GWh/year. They may also issue a certificate of public convenience for construction of an international power line having a capacity of less than 5 MW. Under emergency conditions the NEB may unilaterally authorize exports to American customers who are interconnected with Canadian systems.

Under normal circumstances it takes twelve months for the Board to process a major application for a certificate or license. If an application is approved, the Board prepares an Order-in-Council document which is submitted to the Minister of Energy, Mines and Resources. The Minister recommends the project to the Governor-in-Council, at his discretion. A decision by the Board to approve a license is not effective until approval of the Governor-in-Council is received.

[3]National Energy Board Act Part VI Regulations; 1978.

The NEB licenses interruptible energy, firm power, short term power and wheeled power separately. Each license fixes a maximum export limit, normally on a per annum or on a 12 consecutive month basis. The license also establishes minimum prices. The licensee however may negotiate within these prescribed limits and general conditions.

Any subsequent amendments to the conditions in the interconnection agreement or the price must be approved by the Board.

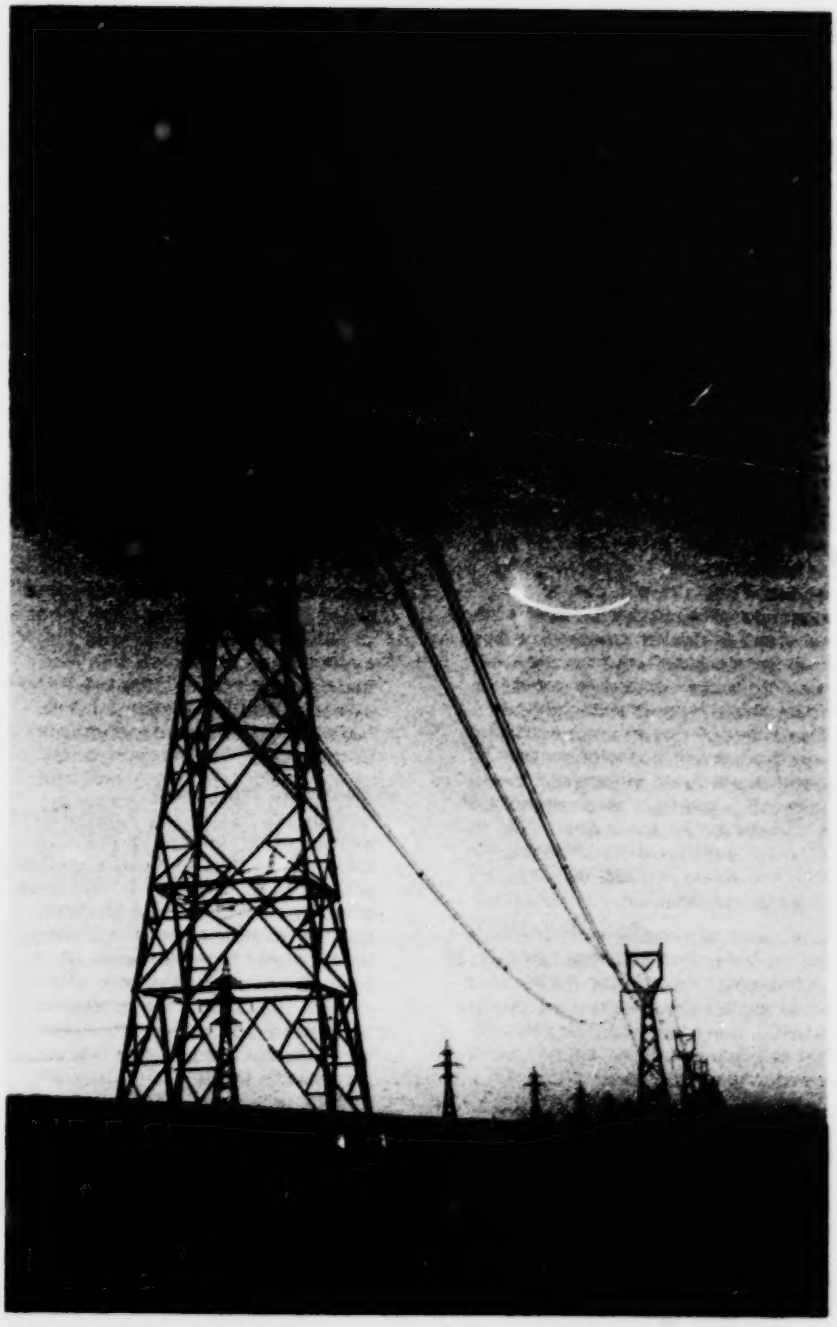
3.2 Government Jurisdiction – United States

The power industry in the United States is regulated by federal and state levels of government. The federal government has jurisdiction over electricity exports made by investor-owned utilities and over the construction of electrical transmission facilities at the international boundary.

There is overlapping jurisdiction over regulation of construction of international transmission lines. State public utility commissions have jurisdiction over transmission facilities by virtue of their authority to regulate state generation and transmission facilities. Because federal authority applies only to border crossings, state governments have main control over line routing, design and operation. In some instances, the location of transmission facilities may require review and approval by counties and towns.

Construction of international transmission facilities is authorized by Presidential Permit. While the Department of Energy has the authority to review permit applications, information may be provided by the Environmental Protection Agency and the Corps of Engineers. All applications must have approval from the Secretary of Defence and the Secretary of State.

The Department of the Interior must approve any application for transmission facilities crossing federal lands, Indian reservations, or through specified wildlife habitats.



The Winnipeg-Minneapolis 500 kV transmission line which constitutes Manitoba's third interconnection with the American Power Grid.

3.2.1 United States Licensing Procedures

Unlike the National Energy Board, the Department of Energy does not have specific criteria against which permit applications are evaluated. Permit applications are reviewed individually.

Each case is evaluated on the environmental, technical and economic information submitted. Consideration is given also to information obtained through the public hearing process and subsequent submissions provided by the applicant. Approximately 6 months are required to process an application. Between 18 and 24 months are required if an environmental impact statement is necessary.

4. International Co-ordination

Extensive interconnection systems have developed within Canada and the United States and between the nations. This is due in part to economies of scale associated with the ability to deliver power to mutiple load centres from large plants, including those located in remote areas. While system reliability has been enhanced by interconnections, there have been occasions where disturbances have interrupted the supply of power to a large number of customers at the same time. The collapse of the New York/Ontario interconnection in 1965 was a dramatic example.

As a result of industry-wide planning and co-ordination activities directed at system security, through the North American Electric Reliability Council (NERC), there is greater assurance that extended outages will be avoided or reduced in duration.

NERC was formed as a voluntary organization in 1968 to increase reliability and adequacy of bulk power supply systems in North America. Nine regional councils are represented in NERC. Individual memberships consist of representatives from all major power systems. Members in Canada include British Columbia Hydro, Ontario Hydro, Manitoba Hydro, New Brunswick Power, Hydro Quebec, TransAlta Utilities and Saskatchewan Power. NERC bylaws allow a representative from the NEB and United States Department of Energy to participate as observers.

5. Benefits

Electricity exchanges between Canada and the United States offer a wide range of technical, economic and social benefits to the utilities and customers in both countries. The following description of the benefits of increased international transactions was presented in the Canada/United States Electricity Exchanges Study.[5]

- *Reliability and Reserve Sharing*: Contractual agreements for mutual emergency support between utilities can be used to improve total system reliability or to reduce the operating reserve margin requirement of each activity.
- *Load Diversity*: When two electric utility systems in adjoining areas, or relatively close areas experience their peak loads at different times of the year the systems can be served with less installed generating capacity if the system loads are combined. This "shared" generation concept benefits both systems.
- *Surplus Energy Sales*: Energy not needed by a generating system at the time of its availability can be sold to a secondary market (i.e., another utility) or (in the case of hydroelectric energy) stored in another utility's reservoirs. Energy sources which provide energy beyond current requirements include run-of-river hydro and storage hydro during high water years (when water would otherwise be spilled). In the future they may include solar and wind electric generators and tidal power. The ability to use this surplus energy efficiently will reduce operating costs and conserve fossil fuels.
- *Economy Interchange*: Economy interchanges occur where the incremental cost* of one utility is less than the decremental cost** of another utility. Efficient generating units or variations in fuel cost provide energy at a cost lower than the purchasing system can generate using its own equipment.
- *Unit Power Economies of Scale*: Large generating units are more cost-effective in supplying electricity than smaller generating units. However, when a utility is unable to install the optimally sized unit, international transactions allow electric utilities to plan their system expansion jointly and install larger units. Both utilities benefit financially by the arrangement.
- *Coordinated Operations Scheduling*: By coordinating maintenance schedules of generating units, utilities ensure efficient operation.
- *Use of Complementary Technologies*: Many types of generation technologies complement each other. Historically, cooperation between hydro- and thermal-based systems has been most productive. During low water years the hydro units provide peaking capacity while the thermal units supply base load energy. In good water years hydro generation would normally displace more expensive thermal generation.
- *Reduction of Oil Dependency*: Efficient operations and increased use of coal-fired plants and renewable resources reduce oil use for generating electricity. This is made possible through increased inter-utility electricity exchanges. Any oil dependency reduction lowers the level of foreign imports.

[5] Canada/United States Electricity Exchanges Study, May 1979.

* Incremental cost is the cost of the next available kilowatt-hour of generation on the supplying system.

** Decremental cost is the cost of the next available kilowatt-hour of generation on the purchasing system.

- *Local Economy*:
  Construction of generation and transmission facilities for export purposes creates jobs and increases the tax base in the exporting area.

Canada also benefits from electricity exports in the following ways.

- *Revenues*:
  Export revenues lower the cost of service to customers served by the exporting utility. The revenues can be used to offset rate increases or put toward financing new facilities, thereby reducing external financing requirements.
- *Balance of Payments*:
  The revenue from electricity exports improves Canada's balance of payments. In 1981, net export revenue was $1.1 billion, representing about 30 per cent of Canada's energy trade balance and 9 per cent of total electric utility revenue.
- *National Goals*:
  Federal government policy through NEB regulation supports exports subject to appropriate safeguards for supply to Canadian customers. The National Energy Program Update supports prebuilding nuclear plants dedicated initially for the export market on a commercial basis. The may help preserve the CANDU as one of Canada's energy sources.

6. Constraints to Increased Electricity Trade

The benefits support increased trade in electricity but there are constraints which discourage Canadian exports to the United States.

- *Jurisdictional Considerations*:
  In the United States there is overlap in jurisdictional rights between state and federal governments with respect to transmission line approvals. Overlapping jurisdiction increases the potential for delays in the approval process and often results in increased project costs. In cases where a transmission line traverses several states approval is required from each state. This is not always forthcoming.
- *Environmental Considerations*:
  There are environmental issues associated with increased trade in electricity. Large and vocal groups lobby against any policy of increased exports which could cause environmental damage to the exporting nation. These concerns are raised mainly against exports from coal-fired facilities with acid emissions, and against building nuclear plants initially for export.

  Discussions continue between Canada and the United States on acid rain reduction and efforts are being directed toward negotiation of a formal cooperative agreement. The Canadian Government's pursuit of an acid rain agreement has been seen in some American circles as an attempt to improve Canada's opportunity to export electricity.

  This argument has come mainly from politicians representing coal-supplying areas where utilities would be forced to use costly acid-emmission abatement equipment. This could make Canadian energy imports economically attractive for those regions.

  Opponents to building nuclear plants in advance of domestic requirements argue that Canadians would keep the risks and wastes from these plants, while exporting benefits to the United States. However, the volume of nuclear waste is low and safe disposal methods are being studied.

  There has been opposition at the local level to transmission line siting in both Canada and the United States even for domestic supply of electricity. This opposition is especially strong where lines cross regions deriving no benefit from the trade.

  Attempts are being made to provide prompt decisions on issues while ensuring adequate opportunity for the public and special interest groups to express their views.

  Most provinces have introduced changes in legislation or governmental procedures to streamline the approval process. The intention is to avoid economic penalties from delays or revisions while allowing full consideration of social issues.
- *Reliability of Supply*:
  One of the objections raised by American utilities to increased imports of Canadian electricity is reliability of supply. Although on a national scale Canadian imports account for approximately 1.5 per cent of total United States generation, on a regional basis (notably the northeastern states) it rises to approximately ten per cent.

  This is of concern to utilities considering firm imports of electricity as an alternative to constructing their own plants. Canada has responded by indicating that exports have never been curtailed unilaterally contrary to an agreement.
- *American Pricing Regulations*:
  Investor-owned utilities in the United Stated are permitted to earn a profit on capital invested in plant and equipment. Because investor-owned utilities are generally prohibited from making a profit on power purchases, the benefit of imported power costs are passed directly to customers. In the absence of profit incentive, investor-owned utilities may be less motivated to pursue Canadian power purchases.
- *Load Growth*:
  Low load growth in the United States may reduce the need for imports from Canada.

7. Opportunities for Increased Electricity Trade

Given sufficient transmission capabiltiy and favourable licensing conditions (licenses of sufficient duration to warrant United States investment in transmissions facilities), opportunities exist to increase electricity exports until Canadian domestic requirements reach the level of generation capacity.

Opportunity for increased trade exists for fossil fuel displacement, and for new capacity in oil where Canadian capacity would have an economic advantage in the United States.

Exports could come from plants in operation or from those under construction. Alternatively, exports could be generated at stations built initially for this purpose. Hydro capacity is particularly well suited to the pre-building concept. Because hydro facilities have a useful life beyond 60 years, a facility could be licensed initially for exports over 20-30 years and still contribute substantially to domestic demand following termination of the contract.

Hydro potential in Manitoba, Quebec and Newfoundland (Labrador) is large and would be well suited for long term export. It will not be required for domestic purposes for several years.

In addition to potential exports from dedicated plants there exists substantial surplus generating capacity in Ontario (some 6,000 MW by 1990, primarily modern high efficiency coal-fired units displaced by nuclear), Manitoba (hydro) and Quebec (5,000 MW of hydro by 1985).

8. Summary

There is a long history of electricity exchange between Canada and the United States to the mutual benefit of both countries. Policy governing Canadian exports has gone through several stages. The laissez-faire attitude of the early years gave way to regulatory policies of a restrictive nature. These were replaced by policies encouraging exports subject to the protection of Canadian interests.

The benefits derived from trade in electricity relate to energy source differences between Canadian exporting regions and adjacent American importing regions.

Canadian utilities plan their generation and transmission facilities primarily to meet the electricity demand of their own customers and exchanges have been largely incidental to this primary objective. Approximately 80 per cent of current transactions are for interruptible exchanges which can be discontinued at the option of the supplier if needed to meet own system needs.

Some Canadian utilities have large generating capacity surpluses which could produce substantial revenue on the export market. The opportunity to increase income, together with forecast opportunities to incur savings, presents a challenge to Canadian utilities and to the provincial and federal governments.

The nature of the electric utility industry makes it appropriate for negotiations on export and import contracts to take place between participating utilities. It is incumbent on governments however to provide an efficient, understandable and predictable environment within which utility negotiations can succeed. Their efforts will ensure that consumers in Canada and the United States will continue to enjoy the benefits of electricity trade.

EXPORTS AND IMPORTS

International

Electricity exports in 1982 represented 9 per cent of net generation in Canada, while imported electricity accounted for less than 1 per cent of total demand. Net exports to the United States decreased by 7 per cent from 1981, to a total of 31, 366 GWh, i.e. exports of 34,214 GWh and imports of 2,848 GWh.

Manitoba was the only province to show a significant increase in net exports in 1982; they increased by 45 per cent to 5,041 GWh. Better water availability accounted for the increase; water supplies were abnormally low in 1981.

Ontario and Quebec exports were approximately the same in 1982 and 1981. New Brunswick experienced a 7 per cent decrease and British Columbia a 49 per cent decrease. The British Columbia decrease resulted mainly from decreased water supply in 1982 from the abnormally high level in 1981. Since exports from Quebec, Manitoba and British Columbia are entirely from hydro and displace fossil-fuel in the United States, exports are related to surplus water supply and generation capacity. However they may also be limited by the availability of interconnection capabilities. The Quebec interconnections have been fully loaded during the last two years, precluding an increase in exports from the province until the interconnection capacity is expanded (see Table 6). More information on exports and imports by province is provided in Table A5 and Figure 4.

While net exports decreased in 1982, it is evident from Table 7 that energy exported to the United States and the revenue received have increased in the six year period from 1977. The primary reason for increased exports is displacement in the United States of costly electricity generated from oil and coal. Canadian electricity exports are generated primarily from hydro and coal. Comparatively small amounts of oil-generated exports come mainly from New Brunswick, under a contract negotiated with New England utilities before the major oil pricing increases. This contract ends in 1986. Most of the coal-fired exports are from Ontario.

Hydro generated exports are expected to remain stable or increase slightly relative to total exports. Nuclear exports are expected to increase, coal-fired exports to decrease and oil-fired exports to be largely eliminated after 1986.

There are approximately 30 Canada-U.S. interconnections of 69kV or over with power transfer capacity near 10,000MW. A 230kV interconnection between Saskatchewan and North Dakota was added in 1982. Planned additional or upgraded interconnections between Canada and the United States are indicated in Table 8.

1982 was a significant year for electricity exports to the United States: a) The New Brunswick Electric Power Commission received approval from the National Energy Board to export 335 MW of firm power from the 630 MW (net) capacity of the Point Lepreau nuclear plant completed in 1982. At year end the utility had contracted to export 205 MW under agreements requiring importing utilities to pay a share of the plant costs proportionate to their share of plant output. The contract term is to 1990, with options to extend for a subsequent two years. Export of an additional 60 MW is being negotiated on a similar basis.

This is the first export of firm power from a Canadian nuclear plant. It will greatly reduce N.B. Power's financial risk from this plant.

b) Hydro-Québec entered into two agreements for long-term exports of interruptible power to New York and New England. 111 billion kWh of interruptible energy will be exported to New York between 1984 and 1997. 33 billion kWh of interruptible energy will be exported to New England between 1986 and 1997.

A novel feature of the Hydro-Québec/ New England agreement is an energy banking arrangement. New England utilities will send power to Quebec during periods of low requirements on their systems. This will allow Hydro-

Table 6. Major[1] Interconnections Between Canada and the United States

Province	State	Voltage	Power Transfer Capability
		(kV)	(MW)
New Brunswick	Maine	345	600
Quebec	New York	765	1400
	New York	2 x 120	200
			50
Ontario[2]	New York	230	470
		230	400
		2 x 230	600
	Michigan	230	535
		230	515
		345	710
		345	760
Saskatchewan	North Dakota	230	150
Manitoba	North Dakota	230	150
	Minnesota	230	175
	Minnesota	500	1000
British Columbia	Washington	230	350
		230	300
		2 x 500	1400

1. 100 MW capacity or over.
2. The transfer capability of several lines may not be equal to the mathematical sum of the individual transfer capabilities of the same lines.

Québec to generate less power and use less water. The water saved can be stored in Quebec system reservoirs to be used for generation during periods of high energy requirements in New England.

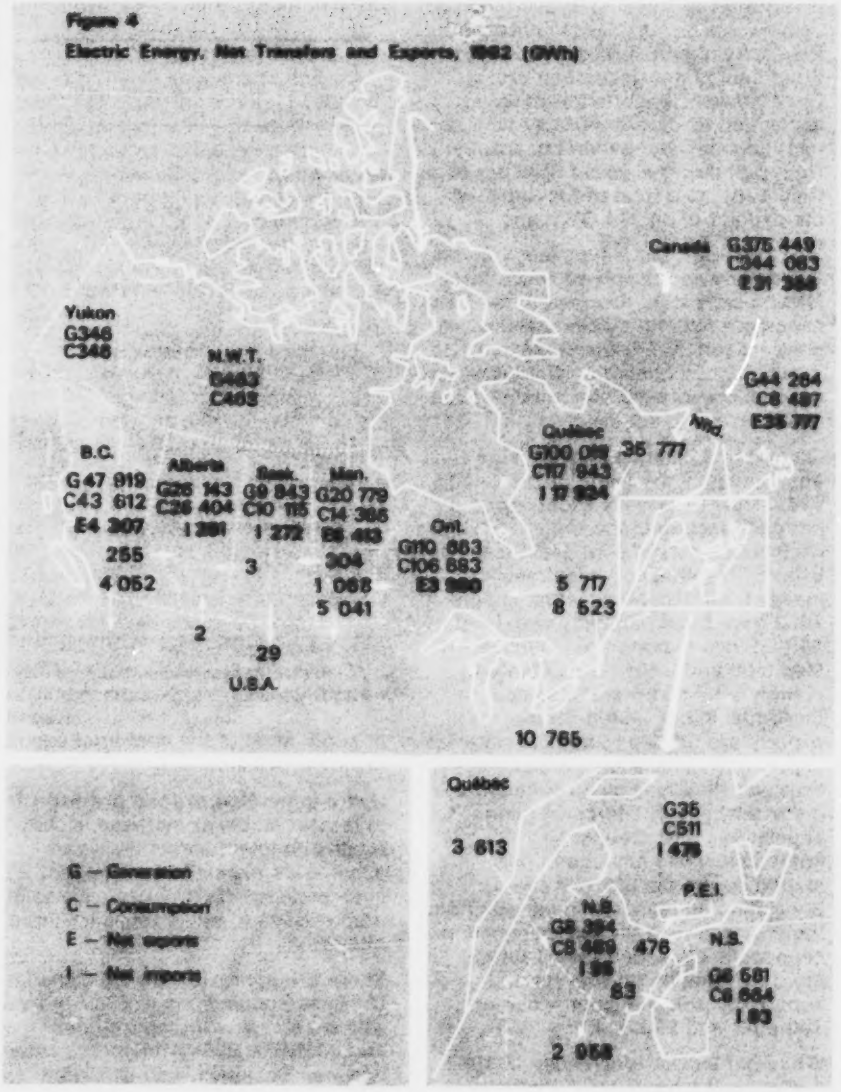
The agreement requires Hydro-Québec to build new transmission facilities in the Eastern Townships area and a high voltage direct current (HVDC) converter station near the Quebec-Vermont border. Its initial capacity will be for 690 MW, expandable to 2000 MW when additional export agreements are negotiated with New England. Hydro-Québec expects to have surplus energy available for export until 1990 as a result of its reduced forecast load growth.

c) Ontario Hydro lost a major export opportunity during the year. An agreement was cancelled by General Public Utilities (GPU) of New Jersey for export of 1000 MW of firm power between 1985 and 1995 via an HVDC cable interconnection across Lake Erie. The NEB approved the export but GPU terminated the agreement on the grounds that cost escalation of the interconnection made the arrangement uneconomic for them. GPU purchased the power instead from mid-western United States. utilities, which supplied the power from old coal-fired plants slated for retirement.

Environmental groups in Canada, including the federal Department of Environment, intervened against the export at the NEB hearings. They argued that additional power generated from the Ontario Hydro Nanticoke coal-fired plant would result in increased levels of acid rain in Canada, already a major problem. This issue was not resolved, since the agreement was terminated, but it could become a major point of consideration in the future.

Proponents of the export argued that less acid rain would fall in Canada if GPU purchased their power from the modern Nanticoke plant rather than from older, less efficient plants in the United States. In addition Ontario Hydro is committed to a 50 per cent reduction in acid-emissions by 1990.

Figure 4
Electric Energy, Net Transfers and Exports, 1982 (GWh)



Applications before the NEB in 1983 include the two Hydro-Québec agreements, and an application from N.B. Power to export 135 MW to Central Maine Power Company.

The nature of electricity exports is changing. In the past, 80 to 90 per cent of exports have been for interruptible energy, displacing fossil-fuel generation in the United States. The change is toward more emphasis on long-term exports of firm energy and capacity for up to 25 years. These exports may allow United States utilities to defer generation capacity additions and to displace more fossil-fuel generation. Exports may come from existing capacity, from plants now under construction, or from plants built initially for export purposes. For example, N.B. Power, supported by the federal government, is offering to build a second 630 MW unit at the Lepreau nuclear plant for long term exports. Both Quebec and British Columbia have offered to build hydro plants for long-term exports.

Table 7. International Electricity Trade, 1977-1982

	1977	1978	1979	1980	1981	1982
				(GWh)		
Exports [a]	18 509	20 542	30 491	28 229	34 730	32 986
Imports [a]	1 060	185	24	169	466	268
Net Exports	17 449	20 357	30 467	28 060	34 264	32 718
Generation source for exports: [b]						
Hydro	5 738	6 984	14 941	12 336	19 948	18 574
Imported Coal	8 514	10 476	11 587	10 599	10 901	10 315
Imported Oil	2 961	2 260	3 354	2 867	1 940	1 959
Canadian Fossil Fuels: (coal and oil)	555	411	128	593	665	502
Nuclear	—	—	177	30	42	96
Other [c]	740	411	305	1 804	768	669
TOTAL	18 509	20 542	30 491	28 229	34 264	32 115
Revenue/cost			(million $)			
Exports	419.27	478.55	738.51	793.58	1 143.87	1 105.90
Imports	13.13	1.76	0.70	2.94	5.62	5.41
Net Revenue	406.14	476.79	737.81	790.64	1 138.25	1 100.49

(a) Excludes no-value exchanges.
(b) Estimated from data for major utilities.
(c) Includes purchases for export where the generation source is unknown.
SOURCE: National Energy Board

Arrangements for long-term firm exports are more complex than those for interruptible exports, since both the buying and selling utilities face more financial risk and such arrangements often involve significant investment decisions. Shorter term or interruptible transactions are based on operating decisions for existing facilities, where sales result in lowering total operating costs. These savings are shared between buyer and seller.

The most attractive United States export markets are New England, New York, and California. These states use the largest amount of oil for electricity generation. However, inadequate transmission capacity is a serious constraint to increased exports.

Table 8. Planned Interconnections to the United States

Province	State	Completion date	Voltage	Estimated power transfer capability
			(kV)	(MW)
Quebec [b]	New England	1986	450 DC	690
Ontario [a]	New York	1984	2x345	1 000
Manitoba [c]	Nebraska	1988	±450 DC/500 AC	1 000

(a) Under construction
(b) Proposed
(c) Under serious review
In addition, Quebec expects to have a high-voltage direct current converter station at Châteauguay with a transfer capability of 1000 MW in service in 1984.

Interprovincial

Changes in interprovincial transfers during 1982 were insignificant. New Brunswick would have purchased more power from Quebec but the interconnections between the two provinces are fully loaded. Prince Edward Island continued to draw over 90 per cent of its electricity from New Brunswick.

Quebec and New Brunswick reached an agreement during the year which will increase the interconnection capacity by 500 MW by 1985; the interconnection capacity between the two provinces will be increased by 75 MW in 1983 by a temporary line.

Prince Edward Island explored the possibility of importing energy from Quebec to supplement the power from its 20 MW portion of New Brunswick Power's Dalhousie coal-fired unit. The energy would substitute for energy purchased from the New Brunswick Power system.

There were no additions to the existing interprovincial interconnections given in Table 9. Proposed provincial interconnections are indicated in Table 10. In 1982 Alberta decided to proceed with a 1500 MW hydro development on the Slave River, subject to environmental acceptability. The project is expected to be completed by 1992 at an estimated cost of $8 billion. As a result of this project, Alberta adjourned negotiations with Manitoba for a western power grid from new generating sites on the Nelson River.

The fluctuations in world energy prices since 1973 have caused confusion and uncertainty about the least costly type of energy for new or existing homes. Huge increases in energy costs in the 1970's were followed by decreases in the past two years. EMR Electrical Branch has studied the economic attractiveness of the residential space heating alternatives for new houses and for converting or upgrading conventional oil furnaces.

The primary purpose of the study was to assess the probable impact of electric space heating on the demand for electricity. A second purpose was to inform homeowners of the lowest cost alternative. This article sets out the methodology used in the study, values used for the principal factors and the study results.

Methodology

The study considered alternatives from the consumers point of view, using costs the consumer would incur. The primary methodology used calculated the current costs of capital, maintenance and operating for each alternative over its useful lifespan.

The cost to the consumer was calculated as if paid in entirety in 1983 (life-cycle approach).

A second methodology used was to calculate the number of years required to recover the cost of replacing or upgrading a conventional oil furnace. Decreased fuel and operating costs over several years compensate for initial expenditure (pay-back approach).

The life-cycle approach provides the lowest cost alternative when considering the entire life of the equipment. However, a low pay-back period is attractive to consumers who may change homes within a few years or who wish to compensate for the high level of energy price uncertainty. It might be reasonable for a consumer to choose an alternative with a low pay-back period even though it is not the least cost alternative on a life-cycle basis.

Table 9. Existing Provincial Interconnections

Connection	Voltage	Capability	
		Installed	Firm
	(kV)	(MW)	
British Columbia-Alberta	1 x 138	110	80
Saskatchewan-Manitoba	3 x 230	400	400
Manitoba-Ontario	2 x 230 115	260	260
Quebec-Ontario	4 x 230 9 x 120	1 300	1 300
Quebec-Newfoundland	3 x 735	5 225	4 300
New Brunswick-Quebec	± 80(DC)	350	350
New Brunswick-Nova Scotia	2 x 138 1 x 345	600	600
New Brunswick-Prince Edward Island	1 x 138	200	100

The alternatives considered were as follows:

- For new systems — oil (intermediate efficiency, high efficiency); gas (conventional, intermediate efficiency, high efficiency); electricity (furnace, heat pump, baseboard);
- For conversions — upgraded conventional oil furnace, gas (as above); electricity (as above, plus plenum heaters), and wood stoves.

Principal Factors

The principal factors to consider in this analysis are the cost of the consumer's money, the original cost of the equipment, equipment maintenance costs, fuel prices and the conversion efficiency of the equipment, i.e. how efficiently the equipment converts gas, oil, electricity or wood into heat for the home.

- Interest rate — taken to be 12 per cent, consisting of four per cent basic rate and eight per cent inflation. This represents the cost to consumers for money borrowed to meet costs or the foregone rate of return on money invested.
- The equipment life — taken to be 15 years. This is an average life span taking into account the different types of equipment.
- Original equipment cost — estimates were obtained from contractors and equipment suppliers.
- Conversion efficiency — conventionally accepted figures.
- Maintenance cost — estimates provided by servicing companies.
- Fuel prices — estimates from the National Energy Program Update, electric utilities, and EMR estimates.

Fuel prices have the greatest impact on the results of the analysis. Unfortunately, this is the most unpredictable factor and largely explains the uncertainty about the most economically attractive alternative.

To improve the flexibility of the study, the alternatives were assessed for annual household energy requirements ranging from 2,000 - 6,000 litres of oil. Analyses have been made in each of the past three years to incorporate changes in forecast energy prices. The major findings of the analyses follow.

1) It is difficult to provide a clear guide for homeowners on the least-cost alternative for space heating systems.

(a) Forecast energy prices have a significant impact on the least-cost alternative, and they are unstable. Therefore the ranking of the alternatives change from year to year, or even within a year.

(b) The cost difference between the least-cost alternative and the second or third alternative is often very small. Slight changes in factor values could alter the ranking of the alternatives. In order to avoid misleading conclusions, EMR has therefore decided to leave the results of the study unpublished.

2) In each of the three studies performed to date, use of a non-oil system is preferred in most provinces.

A Comparison of Estimated Conversions with Actual Conversions

Table 11 shows the actual conversions from oil furnaces by province. The conversions were made under the federal government's off-oil grant program (Canadian Oil Substitution Program, COSP) between April/82 to March/83.

The results are similar to the life-cycle assessment of the cheapest alternative in each province. A large percentage of houses in Newfoundland, Prince Edward Island and Nova Scotia converted to wood, the preferred life-cycle approach (PLCA) alternative. This choice was undoubtedly influenced by the fact that conversions to electricity are not eligible for grants in Newfoundland or Prince Edward Island, and grants apply only to heat pumps in Nova Scotia. Gas is not available.

In New Brunswick conversions were consistent with the life-cycle approach assessment, i.e. predominantly to wood with electricity a close second choice. Wood was undoubtedly rejected by some for other than economic reasons, and gas is unavailable.

Table 10. Proposed Provincial Interconnections

Province	Connections	Year	Capability	
			Installed	Firm
	(kV)		(MW)	
British Columbia-Alberta [a]	500 (AC)	1985	800	600
Quebec-New Brunswick [a]	130 (DC)	1985	500	500

(a) Under construction

Since gas is unavailable in many areas of Quebec the life-cycle assessment is not reflected in conversions. Electricity has a favored image, as Quebecers are justly proud of their electricity development accomplishments. The conversions in Ontario are consistent with the estimated results, given uneven access to gas and the inconvenience of wood.

Manitoba presents a different picture. Analysis indicates gas is the cheapest alternative but most conversions have been to electricity.

Figures for Saskatchewan, Alberta and British Columbia show most conversions are to wood. This is logical since most houses with access to gas were already using it and further conversions to gas probably resulted from extensions of distribution lines. Conversions from oil to wood occured mainly in rural areas where gas is not available. COSP grants were not available for conversions to electricity in Saskatchewan, Alberta and most of British Columbia.

In summary, the conversions in each province have been consistent with the results of our study. However, conversion is constrained by factors including unavailability of gas, absence of federal incentives for specific fuels in some provinces, and non-economic reasons for choices. The Manitoba case is unique because the number of conversions to electricity was greater than expected.

Conclusion

Based on this assessment, electricity is the preferred choice in specific instances. For new systems, it is the preferred choice for energy requirements equivalent to 2,000 and 3,000 litres of oil in Nova Scotia, Quebec and Manitoba and for all requirements in Newfoundland and New Brunswick.

For conversion or up-grading of an existing oil furnace, based on the life-cycle method, electricity is the preferred choice only for energy requirements equivalent to 2,000 litres of oil in Quebec. Electricity is the preferred choice for all energy requirements in Quebec and Manitoba based on payback method.

The study indicates that in Newfoundland, New Brunswick, Quebec and Manitoba electricity for heating is likely to have a significant impact on the overall demand for electricity. No assessment has been made on the extent of that impact.

Although the detailed results will not be published, customers should be encouraged to consider converting from oil to other energy sources. In consultation with energy suppliers and contractors, the costs of energy, maintenance and capital can be taken into account as they apply to their individual situations. This is preferable to unquestioned acceptance of the results of a generalized study which may reflect average conditions but not necessarily those of the individual user.

Table 11. Conversions from Oil Furnace Systems April 1982 - March 1983
Canadian Oil Substitution Program

	Number of Units Converted to:					% Conversions to:				
	Gas	Electricity	Wood	Propane	Total	Gas	Electricity	Wood	Propane	Total
Newfoundland	N/A	351*	8463	7	8821	N/A	4*	96	—	100
Prince Edward Island	N/A	—**	3312	86	3398	N/A	—**	97	3	100
Nova Scotia	N/A	20**	12236	455	12711	N/A	—**	96	4	100
New Brunswick	N/A	5690	6572	260	12522	N/A	45	52	2	100
Quebec	24044	35419	22426	946	82835	29	43	27	1	100
Ontario	50376	19242	20047	2562	92227	55	21	22	3	100
Manitoba	2454	4184	1201	128	7967	31	52	15	2	100
Saskatchewan	1746	—**	2381	643	4770	37	—**	50	13	100
Alberta	1271	—**	344	81	1696	75	—**	20	5	100
British Columbia	13077	1106***	10320	684	25187	52	4***	41	3	100
Yukon, N.W.T.	N/A	N/A	880	31	911	N/A	N/A	97	3	100
Canada	92968	66012	88182	5883	253045	37	26	35	2	100

N/A not available
* *Only small section of Province eligible.*
** *Electricity not eligible, except for heat pumps since mid-1982.*
*** *Electricity restricted to regions not served by gas.*

FUEL USE

Electricity production from fossil fuels increased by six per cent in 1982 over 1981. This represents an increase of approximately one per cent, bringing its share of total electricity production to 22 per cent. Coal-fired production in 1982 increased by 9 per cent, oil-fired production increased by 2 per cent and gas-fired production increased by 3 per cent.

The major increases in coal-fired production were in Alberta and Ontario, followed by Saskatchewan, New Brunswick and Nova Scotia. Coal-fired production displaced oil-fired production in Nova Scotia. This oil displacement was offset by increases in oil-fired production in Newfoundland and British Columbia as a result of decreased hydro production created by a decrease in water availability relative to 1981.

Nuclear production declined by 4 per cent to 36 415 GWh in 1982 as a result of extended maintenance on a unit at Ontario Hydro's Bruce station.

Table 12 provides information on utility use of fossil fuels in 1981, the most recent year for which Statistics Canada data are available. It shows Ontario was the largest user of fuels for electricity production in 1981. It accounted for approximately 63 per cent of the total. Alberta was the second largest user, accounting for 20 per cent. Ontario accounted for 42 per cent of fossil fuels used, and Alberta 32 per cent. New Brunswick remains the largest user of oil. However oil use declined by almost 31 per cent relative to 1980 while the amount of coal used increased by eight per cent.

Provinces west of Quebec use Canadian oil, primarily light oil used in gas turbines or diesel plants. In the Territories, Canadian diesel oil is used. All the oil used by the Atlantic region and Quebec is imported from outside Canada. In the Atlantic region primarily residual oil is used for electricity production.

In 1981 Ontario imported almost 80 per cent of its coal from the United States, the remainder came from Western Canada. The coal used by Manitoba was imported from Saskatchewan. Alberta, Nova Scotia and New Brunswick used their own coal. Saskatchewan relies primarily on its own coal, but imports additional amounts from Alberta.

The energy sources of electricity generation are changing significantly. Oil and gas use is decreasing while coal and uranium use is increasing. Hydro as a source remains steady. These changes reflect oil and gas price increases in the past ten years.

Nova Scotia and New Brunswick have used oil extensively but new coal-fired and nuclear plants will increasingly displace oil. In 1985, the last of four remaining coal-fired units at Nova Scotia Power's Lingan plant will be put in service. New Brunswick will double hydro electricity imports from Quebec. Hydro electricity is expected to displace most of the oil-fired generation in Newfoundland, and Ontario has already displaced all of its major oil-fired generation. Alberta is the main user of natural gas for electricity generation but this is being displaced by coal-fired generation.

Table 12. (a) Quantity of Fuel used by Utilities 1981

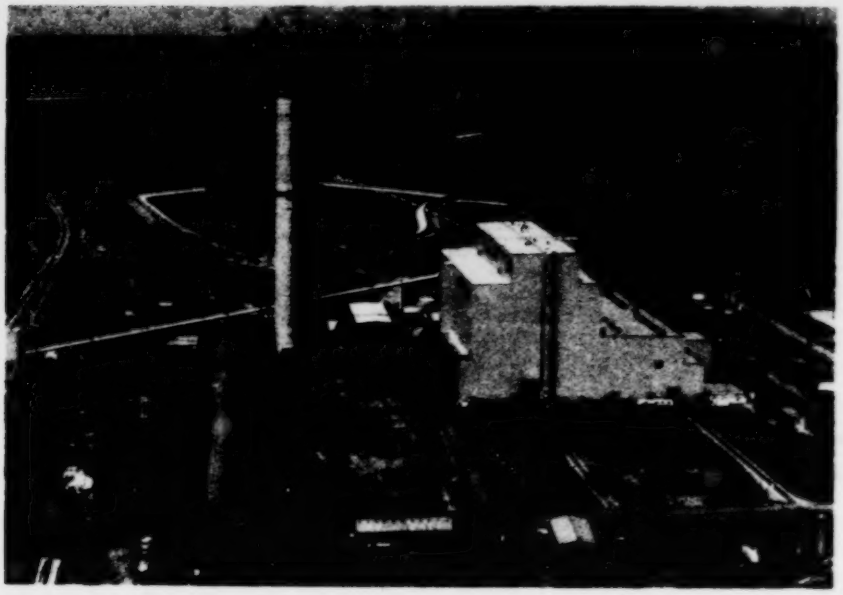
Province	Coal	Oil	Gas	Energy Content	Percentage of total (1)
	(10^3 tonnes)	($10^3 m^3$)	($10^6 m^3$)	(10^3TJ)	(%)
Newfoundland	—	152	—	6	0.8
Prince Edward Island	—	18	—	1	0.1
Nova Scotia	1126	578	—	54	6.8
New Brunswick	515	911	—	52	6.6
Quebec	—	56	—	2	0.3
Ontario	11486	100	9	330	41.8
Manitoba	321	16	*	6	0.8
Saskatchewan	5036	23	148	78	9.9
Alberta	11444	4	1150	255	32.3
British Columbia	—	30	28	2	0.3
Yukon	—	28	—	1	0.1
NWT	—	64	—	2	0.3
CANADA	29928	1980	1335	789	100.0

(1) Total may not correspond to the sum of the elements due to rounding.
** Too small to be expressed.*
SOURCE: Statistics Canada, Publication 57-202

Table 12.(b) Energy Content of Fuel used by Utilities 1981 (10^3 TJ)

Province	Coal	Oil	Gas	Uranium	Total	% of total (1)
Newfoundland	—	6	—	—	6	0.5
Prince Edward Island	—	1	—	—	1	0.1
Nova Scotia	30	24	—	—	54	4.3
New Brunswick	14	38	—	—	52	4.1
Quebec	—	2	—	—	2	0.2
Ontario	326	4	*	465	795	63.4
Manitoba	5	1	*	—	6	0.5
Saskatchewan	71	1	6	—	78	6.2
Alberta	211	*	44	—	255	20.3
British Columbia	—	1	1	—	2	0.2
Yukon	—	1	—	—	1	0.1
NWT	—	2	—	—	2	0.2
CANADA	657	81	51	465	1254	100.0

(1) Total may not correspond to the sum of the elements due to rounding.
** Too small to be expressed.*
SOURCE: Statistics Canada, Publication 57-202



TransAlta Utilities new Keephills coal-fired generating plant at Lake Wabuman. The first unit of the Keephills station is expected to be in-service in early 1983.

FORECAST ELECTRICITY DEMAND, PRODUCTION AND CAPACITY

This section forecasts electricity demand, sources of production, and installed generating capacity for Canada. Additional quantitative information can be found in Tables A6 and A7.

Forecast Demand

Figure 5 shows the close historical relationship between per capita economic performance, as measured by Gross National Product (GNP), and per capita electricity demand. Since per capita economic growth and population growth over the next twenty years is forecast to be significantly lower than that of the previous twenty year period, electricity growth will also be lower.

Table 13 shows growth in the period 1960-1982 of real GNP (i.e. GNP net of inflation), population, primary energy demand (i.e. the total energy available from the energy sources in their original state) and electric energy demand, as well as the forecasts for each of these items for the period 1982-2000.

The table predicts an enlarging role for electric energy in Canada. The percentage of primary energy supplied in the form of electricity is expected to increase from 39 per cent in 1982 to about 43 per cent in 1990 and 48 per cent in 2000.

Recent government initiatives are expected to increase electricity demand. The National Energy Program, introduced by the federal government in October 1980, included financial incentives to convert from oil to non-oil sources of energy, including electricity. To the end of 1982, about 30 per cent of the conversions under this program were to electricity.

Table 13. Historical and Forecast Annual Growth Rates-Real GNP, Population, Primary and Electric Energy

	1960-1982	1972-1982	1982-2000
	(%)	(%)	(%)
Real GNP	4.1	2.5	3.1
Population	1.5	1.0	0.8
Primary Energy	4.0	2.2	2.1
Electric Energy	5.4	4.0	3.3

SOURCE: Energy, Mines and Resources.

This program was strengthened by provincial government initiatives. In 1981, the Ontario Government's Board of Industrial Leadership and Development (BILD) program endorsed electricity as a substitute for other energy forms. In 1982 Quebec offered financial incentives to homeowners to use an electricity-oil hybrid system to supply most of the energy for residential space heating.

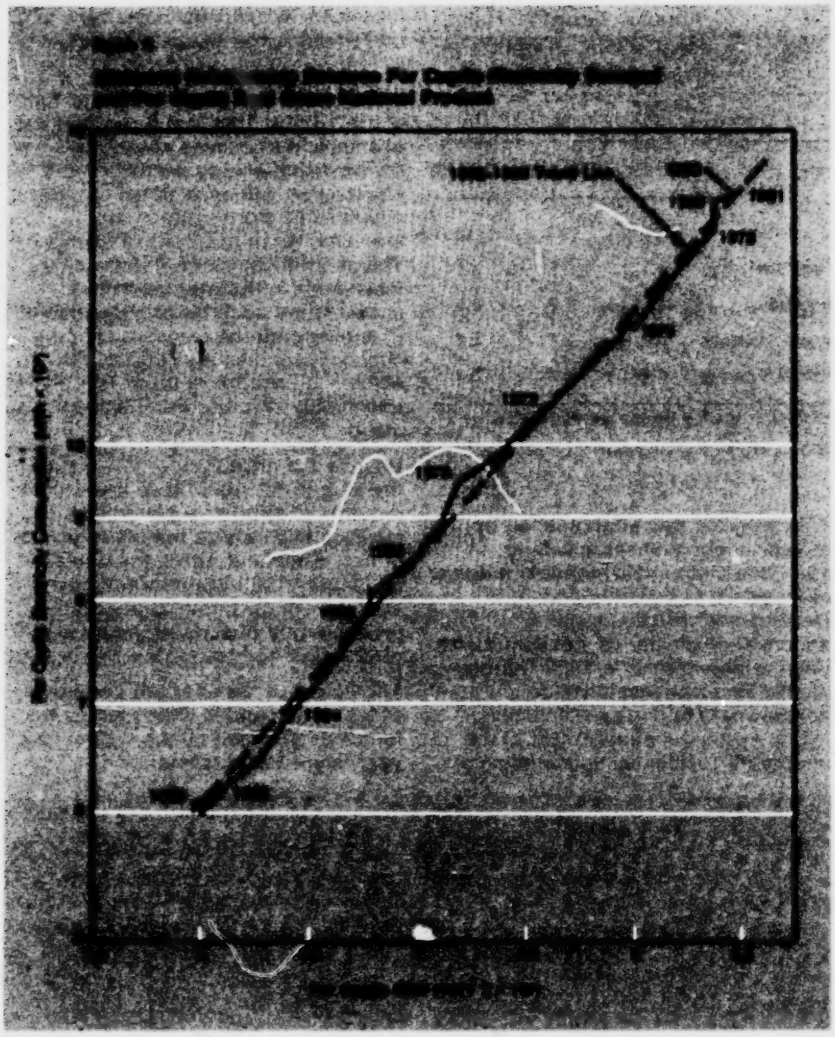
At the same time, Quebec offered incentives to industrial customers to use electricity for steam production.

Forecasting electricity demand became a difficult task in the last half of the 1970's. This was a result of the economic dislocations caused by rapidly rising energy prices. The effects were felt on a global scale and adjustments were made in the amounts, types and uses of energy. The international price decreases in fossil-fuels in the past year have added to the uncertainty. Adjustments in energy patterns continue to make economic forecasting difficult. The economic uncertainty leads to uncertainty in future electricity demand.

Despite the difficulties of forecasting, the long (5-10 years) lead times required to bring new generation facilities into service require forecasts of future demand. Utility forecasts as of January 1983 are provided below in average annual percentages for the probable rate of electricity demand growth.

The extent of the changed perception of future demand is illustrated by the forecasts provided by the utilities last year, shown in brackets.

	1982–1990		1990–2000		1982–2000	
			(%)			
Canada	3.5	(4.9)	2.9	(3.6)	3.2	(4.2)
Newfoundland	5.0	(7.3)	4.1	(4.9)	4.5	(6.0)
Prince Edward Island	1.9	(2.0)	2.0	(2.5)	1.9	(2.3)
Nova Scotia	3.3	(3.3)	3.9	(3.0)	3.6	(3.1)
New Brunswick	3.0	(3.3)	2.2	(2.3)	2.5	(2.8)
Quebec	3.6	(5.1)	2.9	(4.1)	3.2	(4.6)
Ontario	2.3	(3.8)	1.9	(2.7)	2.1	(3.2)
Manitoba	4.1	(4.0)	2.6	(2.7)	3.3	(3.3)
Saskatchewan	3.9	(5.5)	2.6	(2.1)	3.2	(3.7)
Alberta	7.1	(7.3)	5.1	(4.9)	6.0	(6.0)
British Columbia	3.4	(6.2)	3.1	(3.9)	3.3	(4.9)
Yukon, N.W.T.	3.3	(6.5)	3.3	(4.8)	3.3	(5.6)



All provinces but one reduced their forecast demand growth over the period 1982-2000. The changed perception of future load growth was significant, especially in British Columbia, Ontario and Quebec, and there may be further reductions in utility load growth forecasts. This is not an indication that better forecasting techniques are required. It indicates the difficulty of making forecasts of electricity demand with a high degree of confidence in present circumstances.

Rather than single value forecasts, it is appropriate to consider a range of demand forecasts with an assignment of statistical probability to each.

It follows that plans must be flexible enough to meet electricity demand as it develops. It appears that utilities are now taking an approach to planning which includes more flexible supply options. These alternatives might not be considered the most cost effective if there were a high degree of confidence in the demand forecast. They are, however financially attractive in the short term.

Figure 6 includes, for reference, the National Energy Board 1983 base case forecast of electricity demand for Canada. The December 1982 EMR forecast is lower than the NEB forecast.

Included on the graph for comparison is the electricity demand forecast developed by the EMR Electrical Branch, based on forecasts provided by the major utilities. These forecasts are very similar over the long term.

Table 14. (a) Forecasts of Generating Capacity by Type, Canada

	(GW)							(%)					
	Conventional Thermal							Percentage of Total Capacity					
Year	Oil	Gas	Coal	Total	Nuclear	Hydro	Total	Oil	Gas	Coal	Total Conventional Thermal	Nuclear	Hydro
1983	7.8	4.2	16.8	28.8	7.0	51.9	87.7	9	5	19	33	8	59
1984	7.8	4.2	17.9	29.9	8.3	54.9	93.1	8	5	19	32	9	59
1985	7.8	4.2	18.2	30.2	10.1	56.7	97.0	8	4	19	31	11	58
1990	6.9	3.7	20.8	31.4	13.4	59.7	104.5	6	4	20	30	13	57
1995	6.8	3.8	21.7	32.3	15.2	67.9	115.4	6	3	19	28	13	59
2000	6.7	3.5	24.6	34.8	15.2	77.5	127.5	5	3	19	27	12	61

SOURCE: Department of Energy, Mines and Resources, based on forecasts provided by Utilities and the National Energy Board.

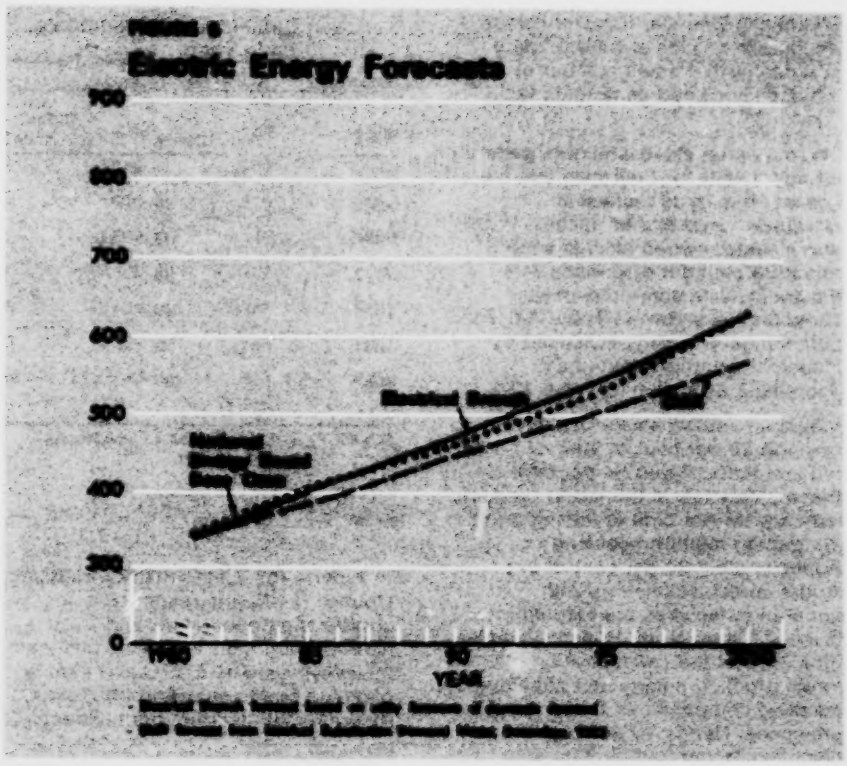
Forecast Production and Capacity

The forecasts for future sources of generation capacity and production are shown in Table 14. This indicates that oil-fired and gas-fired electricity production will continue to decline relative to the total over the period, but will increase slightly in absolute terms. As a percentage of the total generation, oil and gas will be used as the source of about 1.4 per cent in 2000 compared to 5.1 per cent in 1982.

Coal, uranium and hydro will be the major sources of electricity generation and are expected to displace much of the present oil-fired generation in the Atlantic Region during the next twenty years. Most of the remaining oil generation will take place in Ontario and Quebec, for peaking purposes, and in some remote communities.

Table A6 shows that between 1982 and 2000 an additional 26,000 MW of capacity are anticipated. About half of this total will be in hydro additions. Increased nuclear capacity is expected to account for over one third of the total additions and coal for the remainder. This will almost triple the 1981 installed nuclear capacity.

Gas-fired capacity is expected to decrease over this period, while oil-fired capacity will remain at about its present level. Much of the gas-fired capacity is in Alberta, where a significant amount will be displaced by coal additons which produce electricity at a lower cost.



It is likely that the data on the forecast mix of future generation will be reliable. However, the actual capacity additions for a given future year may require upward or downward adjustment to match future electricity demand.

Table 14. (b) Forecasts of Production by Source Canada[1]

	(TWh) Conventional Thermal							(%) Percentage of Production[2]					
Year	Oil	Gas	Coal	Total	Nuclear	Hydro	Total	Oil	Gas	Coal	Total Conventional Thermal	Nuclear	Hydro
1983	6	7	59	72	42	248	362	2	2	16	20	12	68
1984	6	7	60	73	52	254	379	2	2	16	19	14	67
1985	6	8	57	71	63	267	401	2	2	14	18	16	66
1990	4	9	63	76	90	308	474	1	2	13	16	19	65
1995	5	8	71	84	104	359	547	1	1	13	15	19	66
2000	7	9	103	119	108	404	631	1	1	16	19	17	64

[1] To satisfy electricity demand in Canada. Does not include exports to the United States.
[2] Totals may not correspond with the sum of the elements due to rounding.
SOURCE: Department of Energy, Mines and Resources, based on forecasts provided by Utilities and the National Energy Board.

THE ELECTRICITY SUPPLY INDUSTRY IN CANADA

Electric energy is supplied by three sources in Canada. Investor-owned and public utilities are the primary sources, with a small number of industrially-owned generation facilities.

The industrial establishments generate energy mainly for their own use but a few sell energy to municipal distribution systems or utilities. Public and investor-owned utilities supply about 90 per cent of Canada's electricity, with some provincial variations as shown in Table A4. The percentage of energy produced by industrial establishments has decreased as shown in Table 15.

Industrial establishments supply on average 80 per cent of their own total requirements. About 54 per cent of these plants are in the forest products industry, 15 per cent in mining and 11 per cent in metal processing. Approximately 80 per cent of the industrial establishments with generation facilities are located in Quebec, Ontario and British Columbia. This reflects the concentration of forest product, mining and aluminum smelting companies in these provinces. Nearly 90 per cent of the electricity generated by industrial establishments is from hydro-sources.

Greater public ownership of electric utilities has been the trend in Canada, as provincial governments have taken over most investor-owned electric utilities. Consolidation of the supply industry contributes to efficiency and the provincial guarantee of debt lowers the costs of financing. This results in lower electricity supply costs. The provinces also acquire control over electricity supply and pricing policy, considered to be important instruments in socio-economic planning. The major electric utilities in each province and territory are publicly-owned except in Prince Edward Island and Alberta. An investor-owned utility supplies most of the electricity in Newfoundland.

Table 15. Production by Utilities and Industrial Establishments, 1970-1982

Year	Utilities	Industrial Establishments
	(%)	
1970	84	16
1975	87	13
1977	88	12
1979	90	10
1981	90	10
1982	90	10

SOURCE: Statistics Canada, Publications 57-202, 57-001.

In Alberta the Electric Utility Planning Council (EUPC) is responsible for coordinating generation and transmission facilities for all utilities in the province. The EUPC is a central planning body consisting of respresentatives from the utilities.

In Alberta, two investor-owned utilities supply approximately 80 per cent of the provincial supply; municipally-owned utilities supply most of the remainder. The Alberta Electricity Marketing Board will introduce price uniformity for consumers served by the different utilities. The Board, which began operating in September 1982, will reduce price differences by averaging generation and transmission costs. Price differentials due to distribution cost differences will remain.

One investor-owned utility distributes 86 per cent of the electricity used in Newfoundland, including about 90 per cent of electricity used for residential purposes. It purchases about 85 per cent of this electricity from the publicly-owned Newfoundland Hydro.

In the Yukon and Northwest Territories, the federally-owned Northern Canada Power Commission generates and distributes most of the electricity supplied. Two investor-owned utilities supply most of the remainder.

In all provinces but one, most of the electricity is distributed to consumers by the major utilities. The exception is Ontario, where a large proportion is purchased from Ontario Hydro and distributed by some 320 municipal utilities. Statistics Canada publishes the names of the electric utilities in each province in publication 57-204, Electric Power Statistics Vol. I.

The electricity supply industry is an important employer in Canada. As indicated in Table 16, 70,802 people were employed by the industry in 1981. 92 per cent were employed by public utilities, the remaining eight per cent by investor-owned utilities. The utilities had assets totalling $63 billion in 1981, and revenues of $10 billion.

Hydro-Québec, Ontario Hydro and British Columbia Hydro are the three largest electric utilities in Canada, and rank first, second and fifth respectively in terms of assets among all Canadian companies. Hydro Québec and Ontario Hydro ranked second and fifth respectively among North American utilities in net income in 1981. Together these two utilities account for approximately 65 per cent of assets and revenues for Canadian electric utilities.

Comparative data of Canadian utilities and those of the major industrialized countries of the world appear in Table 17.

Table 16. Electric Utility Assets, Debt, Revenue and Employees, 1981

Utilities by Province	$ millions Assets	Debt	Revenues	Employees
British Columbia	8030	6626	1177	4608
Alberta	3819	1410	959	5120
Saskatchewan	1344	1025	315	2166
Manitoba	2822	2539	448	3671
Ontario	19935	14459	2737*	26273
Quebec	20830	15234	2895	22067
New Brunswick	2686	2286	545	2120
Nova Scotia	1078	978	377	2155
Prince Edward Island	75	32	50	232
Newfoundland	2194	1433	352	2055
Yukon and Northwest Territorities	220	189	93	335
CANADA TOTAL (all utilities)	63031	46211	9948	70802

SOURCE: Statistics Canada, Publication 57-202, Ontario Hydro 1981 Annual Report
Note: The totals may not correspond with the sum of the elements due to rounding.
**Adjustment made to revenues in Ontario, to avoid duplication arising from inter-utility sales.*

Table 17. Comparative Data of Utilities in the World's Major Industrial Countries in 1980

	United States	USSR	Japan	Germany	Canada	United Kingdom	France	Italy
Generating Capacity (GW)	631	262	144	87	80	76	67	47
Energy Production (TWh)	2356	2295	578	369	367	285	247	186
Production per capita (kWh)	10350	4382	4945	5990	15316	5093	4591	3256
Average Annual Electric Energy Growth Rate (%)								
1971-75	3.9	6.8	5.4	3.8	6.0	1.4	4.7	4.1
1975-80	3.3	4.5	4.0	4.1	6.1	0.9	6.6	4.8

CAPITAL INVESTMENT

Utility investment in new facilities increased by 18 per cent in 1982, to an estimated $8.6 billion. Approximately 60 per cent was for generation, 20 per cent for transmission, ten per cent for distribution and the remainder for other items.

Table 18 shows the capital intensive nature of electricity supply and its importance in the Canadian economy. The figures show electric utility investment compared to energy supply capital investment, total capital investment and Canada's Gross National Product (GNP). Two five year periods are shown (1966-1975) in addition to figures for 1980-81 and for 1982.

Table 19 shows the original costs of utility fixed assets in service broken down by generation, transmission and distribution.

In Canada as a whole, the costs remain evenly divided between generation and the sub-total of transmission, distribution and "other", including office and storage buildings.

This investment pattern varies from one region to another, depending on the type of generation mix employed. The capital investment per unit of capacity added is significantly higher for hydro and nuclear capacity than for conventional thermal capacity. Hydro and nuclear generation are characterized by high capital cost and low operating cost, relative to a conventional thermal plant. In addition hydro facilities often require higher capital expenditures for transmission facilities because of the remote location of the generation plants.

Table 20 provides information on capital expenditures for electric system expansion by province for 1982, and estimates for 1983 to 1992. The average annual increase in capital expenditures during the forecast period is 5.8 per cent. The rate of inflation is expected to be approximately six per cent during the period so no real growth in capital expenditures is expected.

The forecasts of capital expenditures show a major change from last year. The 1983-1992 total of $97.9 billion is approximately 40 per cent lower, reflecting the lower load growth forecasts in Quebec, Ontario, and British Columbia. (See the section on Forecast Electricity Demand, Capacity and Production). The historical data in Table 21 indicates capital expenditures have increased at an average annual rate of 13.9 per cent since 1965. The average annual rate of inflation over this period was 7.2 per cent, resulting in real growth of approximately 6.7 per cent.

Table 18. Electric Utility Capital Investment

	1966-70	1971-75	1980	1981	1982
Investment in electric power ($ billions)	6.8	12.9	6.4	7.3	8.6
As percentage of investment in:					
Total Energy	55	56	44	40	42
Total Economy	8	9	10	9	11
As percentage of GNP	1.9	2.0	2.2	2.2	2.5

SOURCE: Statistics Canada Publications 61-205 and 11-003E.

Table 19. Original Cost of Utility Fixed Assets in Service

	1971		1975		1977		1979		1981	
	($millions)	(%)	($millions)	(%)	($millions)	%	($millions)	(%)	($millions)	(%)
Generation	7482	48	10549	48	14628	51	19177	52	24943	53
Transmission	3392	22	4802	22	5804	20	7421	20	9632	20
Distribution	3470	23	5007	23	6302	22	7950	21	9554	20
Other	1107	7	1712	7	1968	7	2601	7	3145	7
Total	15451	100	22070	100	28702	100	37149	100	47274	100

SOURCE: Statistics Canada, Publication 57-202

Table 20. Forecast of Electric Utility Capital Expenditures

Province	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	Total 1983-92
						(millions of current dollars)						
Newfoundland	176	200	172	134	168	183	204	231	262	268	268	2090
Prince Edward Island	13	4	4	4	5	6	3	7	7	8	8	56
Nova Scotia	92	177	192	101	86	70	46	46	49	52	54	873
New Brunswick	142	64	52	51	50	56	54	50	50	40	40	507
Quebec	2542	2662	2400	2191	2006	2094	2657	3619	4444	5363	6154	33590
Ontario	2889	3292	3037	2453	2205	2211	2415	2319	2625	2749	2520	25826
Manitoba	97	155	143	114	113	163	410	610	613	598	598	3517
Saskatchewan	256	325	354	337	167	294	361	539	398	408	708	3891
Alberta	820	1007	1139	1084	938	1069	1264	1387	1629	1876	1984	13377
British Columbia	990	972	625	618	764	861	1216	1746	2392	2395	2395	13984
Yukon and Northwest Territories	8	20	17	19	29	12	18	14	14	15	15	173
CANADA	8025	8878	8135	7106	6531	7019	8648	10568	12483	13772	14744	97884

SOURCE: Department of Energy, Mines and Resources based on Utility Estimates.
Fiscal and calendar years combined.

Table 21. Historical Electric Utility Investment

	Construction					
Year	Generation	Transmission and Distribution*	Other	Sub-Total	Machinery and Equipment	Total
			(millions of current dollars)			
1965	438	277	12	727	212	939
1966	493	281	13	787	356	1413
1967	577	262	36	875	390	1265
1968	533	301	54	889	443	1332
1969	511	281	63	856	546	1403
1970	581	449	28	1057	554	1610
1971	572	472	36	1079	668	1747
1972	636	449	50	1135	619	1754
1973	808	539	69	1417	827	2244
1974	1049	598	53	1700	1054	2753
1975	1691	874	96	2661	1296	3957
1976	1803	821	30	2654	1574	4229
1977	2205	911	43	3158	1726	4884
1978	2339	1199	233	3761	2175	5936
1979	2516	1424	181	4121	2243	6364
1980	2470	1433	95	3998	2111	6109
1981	2986	1514	199	4698	2734	7432
1982 (a)				5540	3054	8594

** Transmission and Distribution includes street lighting. Generation includes transformer stations, dams and reservoirs.*
(a) Intentions, breakdown not available.
Note: The totals may not correspond with the sum of the elements due to rounding.
SOURCE: Statistics Canada Publications 57-202, 61-205, and 61-206.
Canada Year Book 1968-79.

FINANCING

From 1960 to 1976, debt for utility expansion increased. Table 22 shows a decline in the debt proportion since 1976 as most utilities tried to reduce financial risk and their exposure to high interest rates. In 1976, debt accounted for 88 per cent of capitalization in provinces with predominantly publicly-owned utilities. It was 51 per cent in those provinces with predominantly investor-owned utilities. By 1982, debt for publicly-owned utilities decreased to 87 per cent and 48 per cent for investor-owned utilities.

The higher degree of business risk for investor-owned utilities in Prince Edward Island and Alberta requires their debt to be a lower percentage of the total capitalization. The debt of the publicly-owned utilities is guaranteed by the provinces in which the utilities are located.

Studies indicate that the debt of a publicly-owned utility should not be substantially above 80 per cent of the capital structure. Some utilities which have a debt portion higher than 80 per cent may take this opportunity of relatively low capital requirements to strengthen their financial positions. The provincially-owned utilities in Newfoundland and British Columbia have policies in place to do this.

The federal government provides loans for the Northern Canada Power Commission, a federal Crown corporation. It supplies most of the electricity in the Yukon and Northwest Territories.

In 1980 utilities used internally generated funds (net income plus non-cash charges to income) for about 30 per cent of capital expenditures. This is approximately the same as for the period between 1965-75. Internally generated funds should meet about 30-35 per cent of capital requirements in the next five years.

Table 22. Electric Utility Financial Structure

Province	1971		1976		1977		1978		1979		1980		1981	
	(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)
						(%)								
Newfoundland	85	15	79	21	76	24	76	24	76	24	74	26	71	29
Prince Edward Island	47	53	53	47	53	47	52	48	53	47	54	46	55	45
Nova Scotia	84	16	103	-3	102	-2	99	1	98	2	95	5	97	3
New Brunswick	88	12	92	8	92	8	93	7	93	7	91	9	91	9
Quebec	73	27	76	24	76	24	76	24	75	25	75	25	75	25
Ontario	67	33	77	23	77	23	78	22	78	22	78	22	78	22
Manitoba	93	7	97	3	97	3	96	4	94	6	94	6	95	5
Saskatchewan	79	21	73	27	77	23	78	22	78	22	80	20	85	15
Alberta	56	44	49	51	47	53	44	56	45	55	42	58	42	58
British Columbia	93	7	94	6	95	5	94	6	86	14	85	15	85	15
Yukon and Northwest Territories	75	25	102	-2	99	1	98	2	98	2	98	2	99	1
CANADA	76	24	80	20	80	20	80	20	78	22	77	23	77	23

(a) Debt: Long-term & loans and notes payable.
(b) Equity: Total of reserves and total capital and surplus.
SOURCE: Statistics Canada, Publication 57-202.

Table 23. Average Revenue from Electricity Sales by Province

Province	1971	1972	1974	1975	1976	1977	1978	1979	1980	1981
	(current cents /kWh)									
Newfoundland	1.1	1.1	1.3	1.4	1.4	1.7	2.0	2.2	2.3	2.8
Prince Edward Island	3.0	3.0	3.7	4.1	5.1	5.9	6.4	7.2	8.1	10.0
Nova Scotia	1.8	1.8	2.0	2.5	2.8	3.9	4.4	4.6	4.5	4.9
New Brunswick	1.5	1.5	1.6	1.9	2.0	2.4	3.2	3.7	4.1	4.8
Quebec	1.0	1.0	1.1	1.3	1.4	1.5	1.7	2.0	2.2	2.6
Ontario	1.1	1.2	1.4	1.6	1.8	2.3	2.4	2.6	2.9	3.2
Manitoba	1.0	1.0	1.2	1.4	1.7	1.9	2.3	2.7	2.8	2.8
Saskatchewan	1.7	1.6	1.6	1.8	2.1	2.4	2.7	2.7	2.9	3.6
Alberta	1.5	1.5	1.7	2.0	2.4	2.7	3.1	3.2	3.4	4.1
British Columbia	1.3	1.3	1.4	1.6	1.8	2.1	2.2	2.4	2.6	3.0
Yukon	2.4	2.4	2.6	2.7	3.5	4.1	4.4	4.9	5.3	6.7
Northwest Territories	2.5	3.2	3.6	4.0	5.2	6.9	7.7	9.0	10.0	11.5
CANADA	1.2	1.2	1.3	1.5	1.7	2.0	2.3	2.5	2.8	3.1

SOURCE: Statistics Canada, Publication 57-202.

Table 24. Monthly Electricity Costs for Selected Canadian Cities, January 1982

Sector	Residential	Commercial	Industrial
Billing demand (kW)	—	100	1 000
Consumption (kWh)	1 000	25 000	400 000
	($)		
Vancouver	40.66	1 063.88	12 172.94
Calgary	37.53	1 193.19	12 040.59
Edmonton	37.65	1 079.26	14 058.26
Regina	36.00	935.60	11 288.40
Winnipeg	30.86	815.31	9 257.30
Toronto	39.83	1 252.80	14 985.00
Ottawa	32.60	849.58	11 994.58
Montreal	34.57	1 175.00	13 724.60
Moncton	52.79	1 719.40	16 970.00
Halifax	49.15	1 587.75	16 411.06
Charlottetown	100.11	2 990.00	37 324.70
St. John's	51.37	1 343.22	15 374.63
Whitehorse	70.51	2 190.50	n/a
Yellowknife	103.06	2 988.00	n/a

n/a: not applicable

SOURCE: Statistics Canada, Publication 57-203

COSTING AND PRICING

Costing

The unit cost of supplying additional electricity increased rapidly during the 1970's. However in recent years cost increases have approximated the rate of inflation, resulting in little increase in the real cost of electricity. In most of Canada few real cost increases are forecast for the 1980's.

In the 1970's there were two basic reasons for rapid increases in the cost of electricity: the increase in the rate of inflation and the increase in the cost of fossil fuels. High levels of inflation affect the electric utility industry in two ways: it increases the capital cost of constructing additional facilities and it increases the cost of funds, an important consideration for a capital intensive industry.

The average interest on new long-term utility debt is shown in Figure 7 for the period 1966 to 1982. The index of electric utility construction costs is shown in Figure 8. This figure shows the significant increase in utility construction costs between 1973 and the present, a trend shared by most capital projects. Construction costs parallel the Consumer Price Index (CPI) prior to 1973 and from 1976 to the present. However, they increased rapidly during the period 1973 to 1977 relative to the rate of inflation, as measured by the CPI.

Figure 9 indicates the increases in fossil fuel costs experienced since 1973. For Canada in total, the fuel cost per kWh generated from fossil fuels increased five-fold between 1973 and 1980, but oil costs moderated in 1981 and 1982. The impact of the cost increase varies between regions of the country depending on the type of fuel used, its source and the percentage of total energy supply derived from fossil fuel plants. Earlier sections of this publication provide regional breakdowns for fuel use and generation mix.

Pricing

Figures showing average revenue from electricity sales for each province are provided in Table 23. The unit revenue for Canada was stable up to 1972, when the cost escalated for reasons outlined in the section on Costing.

These costs increased more rapidly in some regions than others, depending on differences in generation mix, fuels used, and rates of system expansion to meet increased demand for electricity. Table 24 gives monthly electricity costs for selected Canadian cities. Table 25 details the average annual rate increases for customers in each province since 1975.

Table 25. Average Annual Rate Increases, 1974-1982

Utility	(%)							
	1975	1976	1977	1978	1979	1980	1981	1982
B.C. Hydro	6.2	14.2	12.1	13.4	5.5	7.6	2.6	20.0*
Alberta Power	21.3	11.4	20.2	—	—	12.3	28.9	-11.6*
Trans Alta. Utilities	17.6	25.8	14.7	15.6	7.5	—	13.0	4.0
Edmonton Power	13.6	10.1	6.0	8.1	—	26.0	12.0	13.2
Saskatchewan Power	27.0	13.0	17.0	3.3	8.3	7.9	16.1	—
Manitoba Hydro	17.4	16.6	15.0	14.9	14.4	—(1)	—	—
Ontario Hydro	11.4	14.9	25.6	5.7	7.7	7.3	10.0	10.0
Hydro-Québec	9.8	10.3	9.9	18.7	13.7	13.3	10.6	16.3
N.B. Power	10.0	12.0	16.6	9.9	7.9	7.8	9.8	—
N.S. Power	4.6	—	43.0	14.0	12.5	—(2)	—	—
Maritime Electric	20.0	(8.0)	17.0	13.0	—	13.1	21.4	—**
Nfld. Light & Power	33.5	13.4	9.8	21.2	12.4	11.8	14.6	—
Nfld. Hydro	—	14.0	8.4	25.0	—	19.0	15.8	—

NOTES
(1) The provincial government froze the rates in 1979.
(2) The provincial government froze the rates in 1980.
(3) Information available only from 1976.
** Based on residential category.*
*** Does not reflect monthly changes to the cost of commodity and fuel adjustment charges.*

Figure 10 illustrates the movements of the electricity and oil/gas components of the Consumer Price Index, and the movement of the Consumer Price Index total. It indicates that the electricity price component increased more slowly than, or equal to, the rate of increase of the CPI for most of the period since 1955. The exception is the period from 1974 to 1977, when the electricity price component increased faster than the CPI rate. The electricity price component has increased more slowly than the oil and gas price indices.

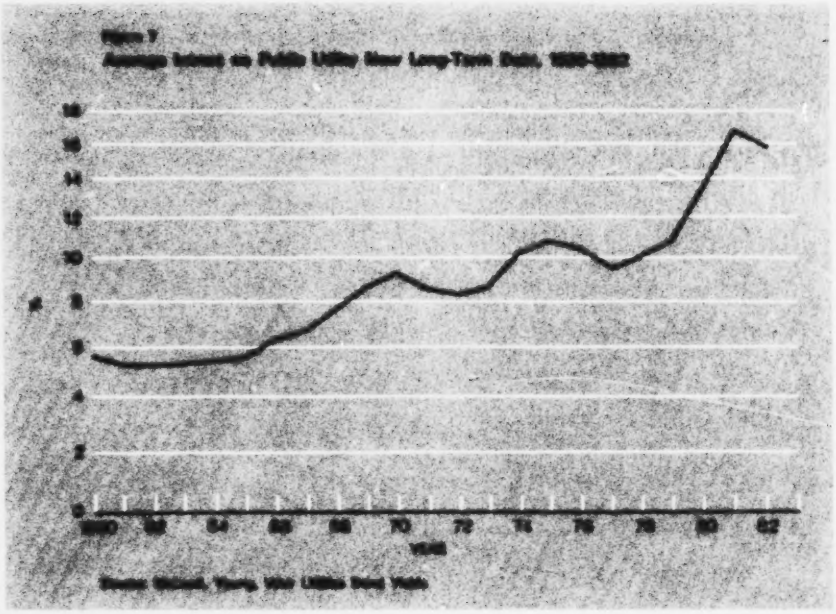
In 1982, the Ontario Energy Board approved time-differentiated rates developed by Ontario Hydro, based on accounting costs. The rates were to be implemented in 1983 for bulk power customers served by Ontario Hydro (municipal utilities and large industrial customers). However the Ontario government decided that the poor economic situation precluded rate structure changes at this time.

In other provinces there has been little public discussion of time-differentiated or other rate structure changes. Several utilities indicate they are moving away from the declining block structure and toward a rate structure of a fixed service charge, plus a single rate for energy. Utilities are also reducing the number of rates.

Hydro-Québec is the only Canadian utility to move from a declining block rate to an inverted block rate structure, which increases the cost per kilowatt hour as more is consumed.

Saskatchewan established a Public Utilities Review Commission in November, 1982. Future rate changes must be approved by the Commission. In 1983, Saskatchewan Power will apply to the Commission for approval of substantial increases to its rates and for structural changes to existing tariffs.

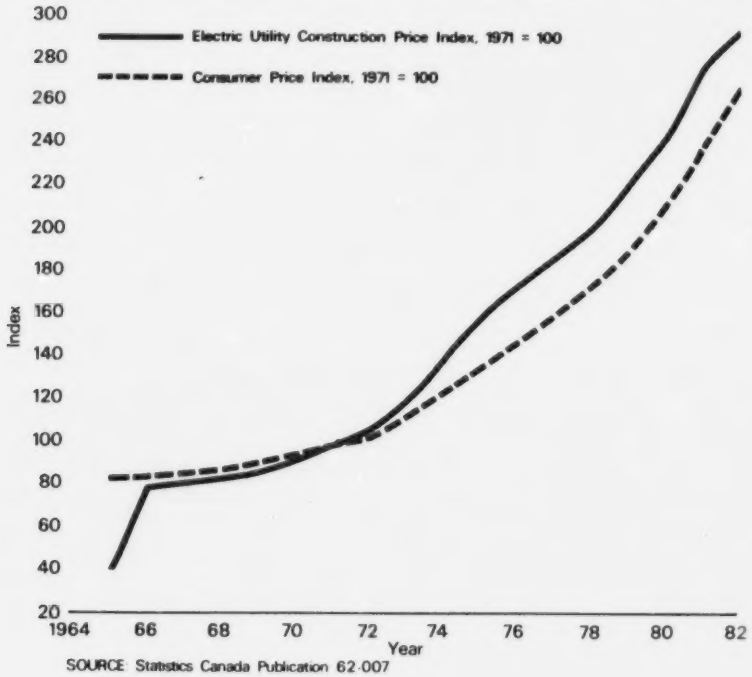
A public enquiry on electricity costing and pricing in Prince Edward Island was held in 1982. More complete information on this enquiry is provided in the Development Section.



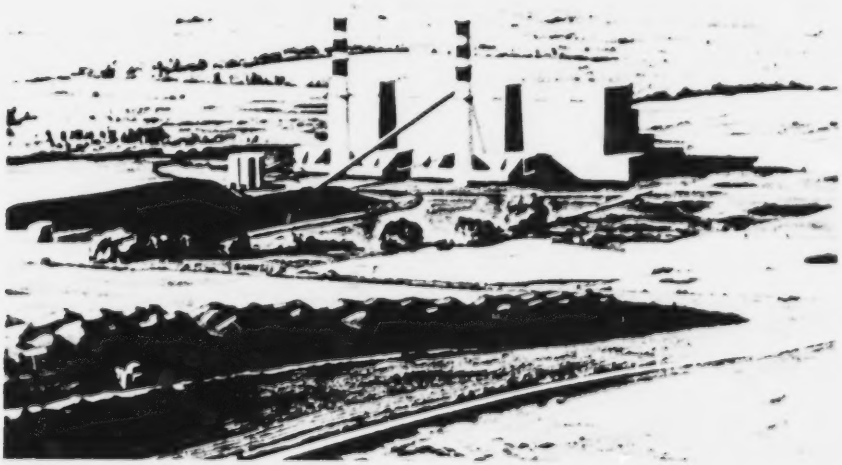
Manitoba Hydro's Long Spruce generating station, the second hydro plant built on the lower Nelson River. It has a generating capacity of 980MW, the second largest power plant in the province.

Figure 8

Price Index Trends in Electric Utility Construction, 1965-1982



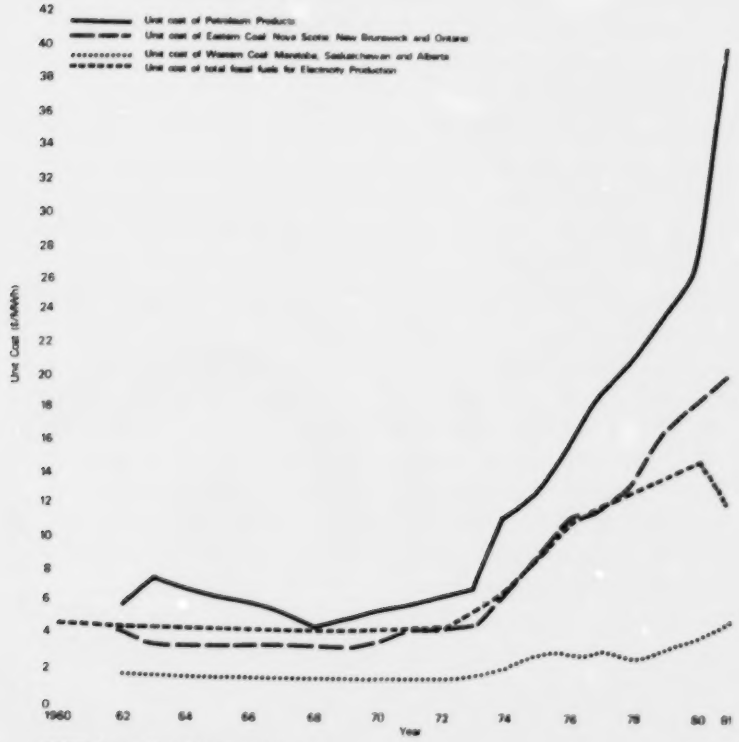
SOURCE Statistics Canada Publication 62-007



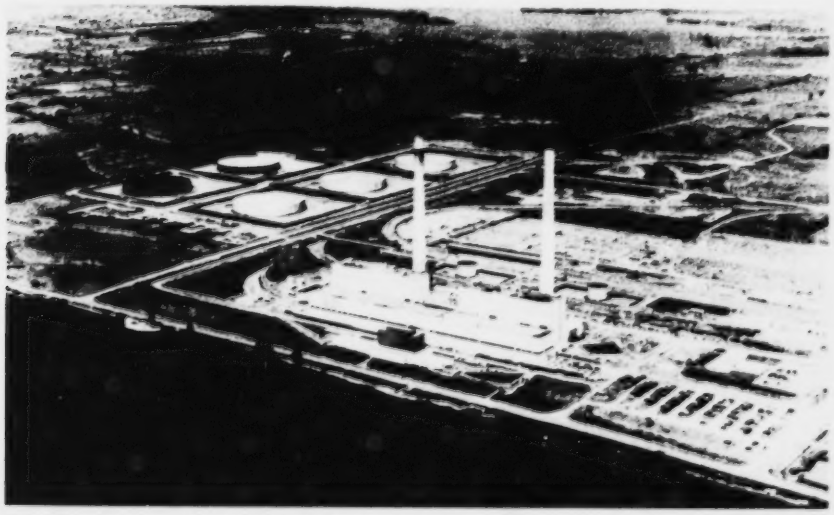
Artist's conception of Edmonton Power's Genesee power project, scheduled for in-service in 1986

Figure 9

Unit Cost of Fossil Fuel for Electricity Production, 1960-1981



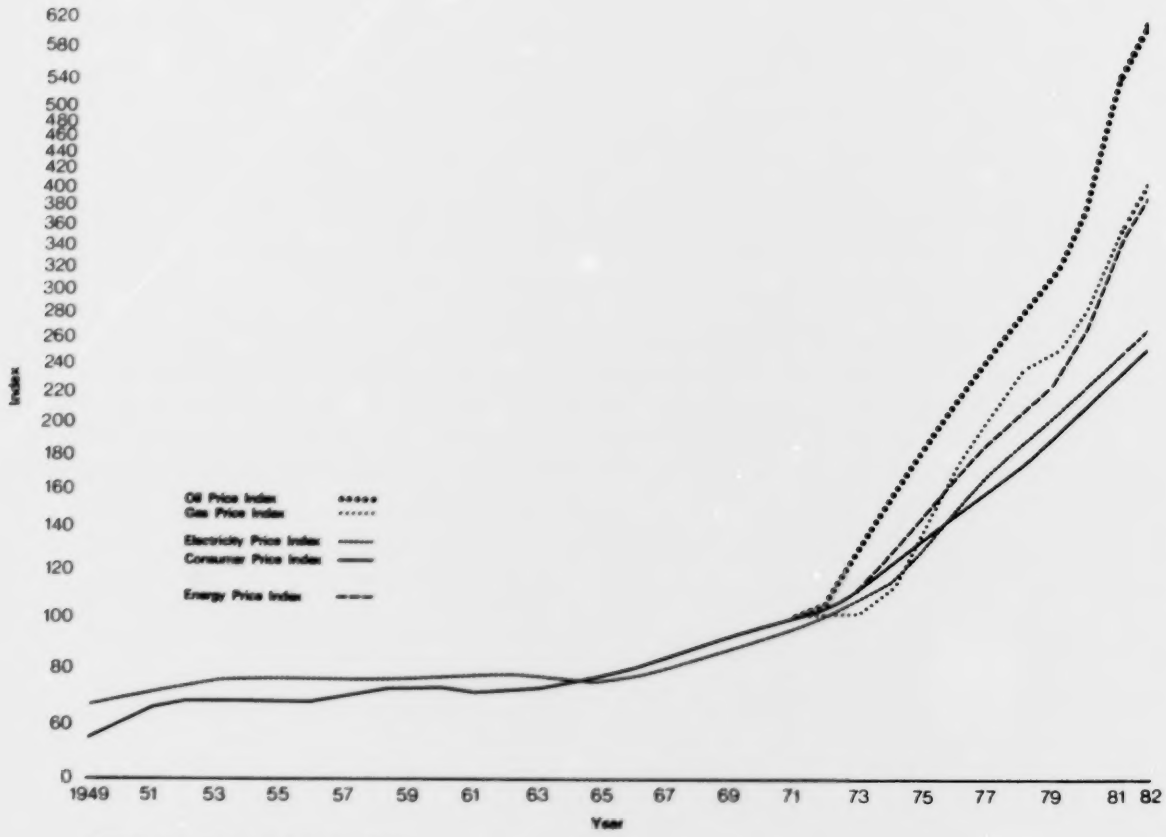
SOURCE: Statistics Canada Publication 57-202



Aerial view of Ontario Hydro's 2295MW oil-fired Lennox generating station, which was mothballed in 1982.

Figure 10

Price Indices, 1949-1982



SOURCE: Statistics Canada Publication 62-010

ALTERNATE ENERGY SOURCES

This section provides an update on the developments in Canada of alternative energy sources. These include geothermal energy, ocean energy, tidal energy, river current energy, small scale hydro, photovoltaics, electro-chemistry and peat.

Geothermal Energy

Federal government geothermal energy research and development funding began in 1976. Originally, the objective of the program was to identify and assess exploitable geothermal resources in Canada. Since then, four types of sources have been identified. These are:

1) Volcanic sources, located in the Cordillera of British Columbia and characterized by high temperature steam flows;

2) Non-volcanic sources in the mountains of Western Canada, characterized by lower temperatures than found in volcanic regions;

3) Sedimentary sources, located in the sedimentary basin of Alberta and Saskatchewan, characterized by uniform but relatively low temperatures over the area;

4) Atlantic sources, which are not uniform but represent an indigenous energy source.

Research is shifting towards extraction technology as knowledge of the resource increases. The work of delineation and development of exploration techniques will continue on all four sources.

The program has identified geothermal resources for potential electricity production at Meager Creek (volcanic source), located 160 km north of Vancouver in British Columbia, and for space heating purposes (sedimentary source) at the University of Regina in Saskatchewan. These sites are being extensively researched.

The potential of the Meager Creek site is estimated to be in the range of 500-1,000 MW of electricity capacity. Following initial federal drilling, British Columbia Hydro continued the drilling program in 1982. Three production-size wells have been completed, to depths exceeding 3,000 m. Although temperatures up to 280°C have been observed, testing indicated fluid flow rates are not sufficient to justify construction of a demonstration generating plant.

At the University of Regina, geothermal energy as a supplementary energy source for the university's central steam generating plant is under consideration. A single production-size hole has been drilled. Although there is not fixed schedule as yet, the large diameter production hole is being studied for heat and fluid flows.

View of the interior of the LG-3 powerhouse during installation of the turbine-generators.

Ocean Energy

The Oceans represent a vast source of renewable energy. Wave energy and salinity gradients hold potential benefits for Canada. Ocean energy sources such as ocean currents and thermal gradients, while not accessible to Canada, are of international interest. Canadian and International Energy Agency (IEA) research and development programs are evaluating the potential of these resources.

An assessment has been made of ocean energy forms in a Canadian context. A prototype generator which extracts energy from salinity gradients by reverse electrodialysis has been developed by a British Columbia company. The feasibility of salinity gradient development is expected to be established over the next few years.

A low level of activity will be maintained on wave energy and thermal gradient technologies. The emphasis will be on state-of-the-art awareness so new developments can be assessed in terms of applicability to Canada. Extraction of energy from the ocean is a long range and site specific endeavour. It is an uncertain competitor with other energy sources in Canada.

Tidal Energy

The Nova Scotia low head hydro demonstration project, situated in the tidal portion of the Annapolis River in Nova Scotia, is expected to be in-service on schedule in mid 1983. The project is expected to provide information on the operation of a single-stage tidal power project and on the cost-effectiveness of the new type of turbine for river and tidal applications.

Current research and development activity is surveying Canadian potential for tidal energy developments and providing technical support for tidal applications.

The National Research Council is developing technology to physically and mathematically model tidal basins. This technology would predict turbine performance and environmental effects such as sediment transport. Similar technical support will continue for the Fundy tidal power project.

Over the next three years surveys will be conducted on the tidal power potential of Ungava Bay. While evaluations on the tidal regime and suitable sites are incomplete, the fully harnessed potential of Ungava Bay could rival the James Bay hydroelectric development.

Energy from River Currents

In 1976, a vertical axis water turbine (VA WatT) was developed by Nova Energy Ltd. (Dartmouth, Nova Scotia) for harnessing energy from the Bay of Fundy tides. The prototype was not selected for demonstration of tidal power. However, it shows potential as an inexpensive method of harnessing energy from river and tidal currents where conventional turbines and small scale hydro are inappropriate.

Vertical Axis Water Turbines combine windmill and hydrofoil technology. A small model was tested at the National Research Council during 1980 and 1981. In 1982, a 10 kW unit was built and installed on the St. Lawrence River near Cornwall, Ontario and hooked to the St. Lawrence Power Company's grid. Two similar units are being developed, one 20 kW unit for a tidal installation in Nova Scotia and a 50-100 kW unit for a low head (small dam) hydro site in British Columbia. The program calls for demonstration of larger units. A 200 kW unit may be available by 1984/85 and a 1,000 kW unit by 1986/87.

The market potential of the VA WatT is considerable. Large scale vertical water turbines could displace diesel fuel in the Canadian north. It is unlikely, however, to displace turbines in the Bay of Fundy. The VA WatT may provide an economic solution to power needs in developing countries and an alternate source of power for homes situated next to small, steady-flowing streams and rivers.

Wind Energy

The major objectives of the federal wind energy Reasearch and Development program are:

(a) To determine the characteristics of wind for use in the design, siting and evaluation of wind energy conversion systems (WECS);

(b) To establish and develop the necessary scientific and engineering principles for understanding and advancing wind energy technology in Canada;

(c) To assess experimentally the performance, structural behaviour and operating characteristics of WECS;

(d) To design, build and evaluate a megawatt scale, grid-coupled, vertical axis wind turbine energy conversion system.

National distributions of wind energy density have been mapped showing the greatest wind power potential. Studies in aerodynamics and structural dynamics of rotors is continuing with attention being directed toward drivetrain, controls and systems engineering aspects of WECS. Four grid-coupled systems (usually 50 KW) and a stand alone wind/diesel hybrid system are being tested in conjunction with provincial utilities and agencies.

The National Research Council (NRC) and Hydro-Québec agreed to share equally the cost of designing, building and evaluating a prototype, megawatt-scale vertical axis wind turbine (project EOLE, previously called AEOLUS). EOLE will have two troposkien shaped blades encompassing a swept area of 4000 square meters. Rated output will be aproximately 3 MW. Six sites are being considered, five in the St. Lawrence Valley and one on Magdalen Islands. Design completion is expected in 1983 and commissionning is scheduled for the summer of 1985. Evaluations will take approximately two years.

Small Scale Hydro

Several provinces are assessing small scale hydro potential and developing demonstration projects. Emphasis is on potential replacement of diesel generation in remote communities.

Analysis indicates economic viability for expansion of existing small hydro stations or the retrofit of decommissioned hydro units within power grids. However, development of new small hydro sites will involve greater capital costs. These costs will restrain development due to the longer pay-back period. A provision in the Federal Income Tax Act allows for accelerated tax write-offs for capital investments in small-scale hydro equipment and this may alleviate the problem. Facilities under 15 MW are eligible for a three-year accelerated write-off under class 34.

Under the Federal - Provincial Conservation and Renewable Energy Development and Demonstration Agreements (CREDA), the federal government supports five small scale hydro projects in British Columbia, one in the Yukon, three in Nova Scotia and one in Prince Edward Island. A similar program was recently announced for Ontario. The program will provide up to $950,000 during 1983/84, with an expected level of funding assistance between 25 and 35 per cent of eligible project costs. Some 25 proposals have been received.

Small-scale hydro development is also supported through the Remote Community Demonstration Program (RCDP). This program was implemented by the federal government in 1982 to meet the special energy problems of remote communities. More than 300 communities across Canada remain unconnected to an electrical grid or natural gas system. The two-phase, four year, $16 million program combines the initiatives of the Remote Community and Arctic Community Demonstration programs. These were originally announced in the National Energy Program.

Phase I of the program, started in October 1982, provides financial assistance for a limited number of community initiated studies to investigate off-oil opportunities. Financial assistance for demonstration of technically and economically feasible energy supply and conservation options will be provided in Phase II.

While the program is not restricted to small-scale hydro development, several hydro projects are the subject of Phase I study proposals. Small-scale hydro technology may prove to be the best supply source for many remote communities.

An earlier study for the Department of Indian and Northern Affairs identified 12 out of 45 load centres as having financially viable, small hydro potential. Through the Native Bands Program, the Department of Indian and Northern Affairs has offered financial support for the development of two small hydro projects in British Columbia at Kingcome Inlet (75 kW) and at Klemtu (250 kW). Other potential projects include one at Sandy Lake in Ontario and Paint Hills in Northern Quebec.

The federal government also funded a consultant study for identification of environmentally compatible small-scale hydroelectric potential in New Brunswick and Prince Edward Island. The project screening and assessment techniques developed during the study will prove useful for studies conducted by utilities.

The Canadian Electrical Association's Research and Development Program, supported by the federal government, has a project on "Simplified Methodology for Estimating Small Capacity Hydro Electric Plants". This project will provide a costing and design guide for the evaluation of small hydro projects.

Photovoltaics

Photovoltaics refers to the technology of direct conversion of sunlight to electricity. Canada has established an industrial base for this solid-state technology. Electricity generation by photovoltaic devices has been limited to low power needs (remote microwave repeater stations) or exotic installations (earth-satellite power supplies).

Photovoltaic technology is a renewable energy option and significant cost reductions have been achieved. Over the next 20 years photovoltaics will have more impact on remote communities than on generation in Canada as a whole. Research and development is aimed at reducing costs. Studies are being carried out on (i) thin film devices based on silicon, gallium arsenide, copper/indium/selenium mixtures and other semi-conductor compounds, (ii) improvements to silicon technology, (iii) remote stand-alone systems and (iv) utility connected systems.

Electrochemistry

There is an established federal government program on hydrogen and energy storage which includes electrochemistry studies, especially on electrolysis for hydrogen production on a commercial scale. Hydrogen production is a probable long-term requirement of Canada's energy system and a significant user of electricity.

The federal government is also conducting some battery research and studying electric vehicles. Most research in these areas is directed by the National Research Council through in-house research or outside contracts.

Peat

Small and medium-scale usage of peat is being examined in Canada. It could be used as fuel for pulp and paper plants and domestic heating. Demonstration projects, largely under the auspices of the federal and provincial governments, will determine the economic and technical feasibility of mining and dewatering peat.

These projects apply current European and Canadian technologies at Bishop's Falls and St. Shotts, Newfoundland; St. Jean, Quebec; and Buffalo Narrows, Saskatchewan. A small peat gasifier is to be substituted for diesel oil to generate electricity on Anticosti Island, Quebec.

The National Research Council's Peat for Energy and Chemicals Program has established a number of long term goals directed to the national use of peat and peatlands. The research program encompasses projects ranging from inventory methodology, through mining and processing technologies to environmental criteria and strategies including land use and management.

The program seeks technologically feasible options which will offer economic benefit. Financial and environmental infrastructures for peat development will not be implemented before establishing technological and economic feasibility and determining the overall impacts of large-scale peat use.

Anticosti Island, Quebec.

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The components that constitute the Straflo turbine arrive at the Annapolis low head hydro demonstration project.

RESEARCH AND DEVELOPMENT

Structure of Research and Development in Canada

Electrical research in Canada is carried out by governments, industry, associations, consultants and academic institutions. Research and development encompasses electricity in a broad range of engineering disciplines, social and economic topics and environmental questions, all of which contribute to the production, distribution and use of this energy form.

At the federal level, the Department of Energy, Mines and Resources (EMR), the National Research Council (NRC), the Natural Sciences and Engineering Research Council (NSERC) and Atomic Energy of Canada Limited (AECL) have administrative and, in the cases of NRC and AECL, functional responsibility for electrical research.

Co-ordination of federal energy R&D is provided by the Interdepartmental Panel of Energy R&D. It makes recommendations to Ministers on present and future energy R&D programs. The Panel's mandate includes monitoring federal energy R&D activities in the context of the whole national effort and international activities.

EMR provides the chairman and secretariat to the Panel. It also provides grants to the Canadian Electrical Association (CEA) and to academic institutions under the Research Agreement Program. Beside in-house research, the NRC contracts to industry.

NSERC provides fundng to academic institutions under regular operating grants, strategic grants and PRAI (project research applicable in industry) grants.

Four of the public utilities (Ontario Hydro, Hydro- Québec, Saskatchewan Power and British Columbia Hydro) maintain in-house research programs which undertake a variety of activities linked with design and operating characteristics of the electric utility business. Manitoba Hydro participates in research activities of the newly established Manitoba HVDC Research Centre, and contributes to the funding of this organization.

The Canadian Electrical Association's research program is funded jointly by the Canadian government and the utilities. The program is designed by representatives from industry and government who identify research topics and manage the performance of studies selected through a sub-committee structure. The studies are contracted out to industry and academic institutions and utilities with research facilities. The participation of utility personnel helps to minimize duplicating studies or neglecting certain areas.

Apart from administering its research program, one of the functions of the CEA is liaison with international research organizations to improve program selection for Canadian utilities.

During 1982/83, research expenditures related to electricity were over $340 million. Of this, $209 million were spent by Atomic Energy of Canada Limited (AECL) on the nuclear power program. Over $112 million were spent by the four electric utilities with research facilities. The co-operative program managed by the CEA received funds of $7.8 million. Finally $11.2 million were spent on federal research and development expenditures relating to electrical energy and to the fuels associated with its production (excluding AECL's program expenditures).

Overview of Research Programs

Federal Government

Research for nuclear power development by Atomic Energy of Canada Limited (AECL) includes maintenance of reliability and safety standards set by CANDU (Canadian Deuterium Uranium) reactors. AECL operates laboratories in Chalk River, Ontario and Whiteshell, Manitoba. Its research mandate is to develop and apply nuclear technology for peaceful purposes to benefit all Canadians. In 1982/83 its resources amounted to $209 million, compared to $198 mllion (1982 dollars in 1981/82 (approximately 80 per cent from Parliamentary appropriations and 20 per cent from commercially generated revenue in each year).

Technical programs continue in power reactor systems, heavy water processes, environmental protection and radioactive waste management, advanced fuel cycles, underlying and advanced systems research and new applications for nuclear technology.

The CANDU reactor's safety has been demonstrated. The moderator's effectiveness as a heat sink would remain unimpaired even if a serious accident were to occur. Construction has begun on a 7-megawatt thermal-hydraulic test facility to verify predictions of primary coolant behaviour under potential accident conditions. Although used nuclear fuel is now stored in the operating plants and occupies limited space, it will eventually be desirable to establish longer duration storage areas for discharged fuel.

Progress has been made in waste disposal in the granite of the Canadian Shield. Systems variability analysis is attracting increasing attention in other countries for application to other wastes. This methodology assesses the consequences of releases from a nuclear waste vault. A major facility for testing the resistance to leaching of used fuel is nearing completion. In 1982/83 construction will begin on an underground research laboratory to study processes and properties involved in geological disposal.

To assure Canadians of a long-term supply of energy from nuclear sources, experiments continue on the recycling of used fuel. Advanced fuel cycles under investigation include the use of both thorium and uranium as feedstocks and the development of fuel assemblies compatible with the current CANDU reactor design.

Processes orginally developed for the production of heavy water are being adopted to remove tritium from the heavy water of CANDU reactors. Tritium could become a useful fuel for fusion reactors.

Research programs in physics, chemistry, materials science and health sciences provide the base for understanding the phenomena involved in the applied R&D programs. The accelerator physics program will be enhanced by the addition of a superconducting cyclotron to the Tandem Van der Graaf accelerator. Future accelerators could be used to breed fissile material for nuclear reactors.

Electric energy is particularly influenced by the non-nuclear areas of the federal energy research program. The objectives stem from the 1980 National Energy Program and include research and development for substitution, alternate energy sources and efficient energy utilization. Emphasis has been placed on environmentally acceptable and energy efficient coal utilization technologies.

The National Energy Program has provided additional funds to expand the core research and development program. $4 million have been designated to support coal R&D in the Atlantic provinces. $150 million will be spent to cover the technical risks of new coal technologies, such as fluidized bed combustion, and use of coal liquid mixtures as a substitute for residual oil.

Two projects have been initiated under this program: a $5.5 million project for construction of a 7 tonne/hour pilot plant in Sydney, Nova Scotia to produce a coal-water fuel and subsequent testing of the fuel in two New Brunswick Electric Power Commission power boilers; and an $8.0 million project managed by Nova Scotia Power Corporation for construction of a 1-metre diameter pilot fluidized-bed for long-term materials of construction tests. Associated research and development conducted in these two technology areas within the federal energy R&D activities provide technical support for the projects and form the basis for Canada's participation in two related International Energy Agency Agreements.

Two alternate energy sources have received particular attention. $18.7 million in federal funds have been allocated to the construction of Tokamak, an experimental fusion device, at Varennes, Quebec. In addition, the EOLE wind demonstration project will receive $17.6 million in federal funds from NRC. It will be capable of generating 3.8 MW and will supply power directly into the Hydro-Québec grid.

A federal sub-program aimed specifically at electric power research is continuing. Activities include research on dielectrics and electrical measurement technologies, and high voltage direct current (HVDC). HVDC research has been conducted by the NRC since 1960. In 1982, a contract was awarded to the Manitoba HVDC Centre.

Electric energy "storage" systems, electric space heating, thermal storage, heat pumps, and rail electrification are some of the other areas being investigated by several departments and agencies with funding through the Conservation Research and Development Program.

The energy conservation program promotes the efficient use of energy and conservation of liquid fuels. Equipment for electricity load control helps flatten load patterns and results in more efficient use of generating capacity and fuel. Substitution options allow conversion to electricity where supply and price permit. There are a number of projects funded under the Conservation R&D program that satisfy both of these objectives.

In conjunction with EMR, the Ministry of State for Science and Technology evaluated hybrid heating and its potential as an efficient user of electric energy. Hybrid heating concepts included the addition of electrical resistance plenum heaters or heat pumps to existing non-electrical heating units (e.g., oil or gas). Consumers could use the electric systems during off-peak hours of electricity demand. During peak periods, non-electric heating sources would be used.

The broad implementation of hybrid heating would reduce peak demand, thereby permitting more efficient use of generating capacity. It would also substantially reduce the need for fuel oil.

To complement the above work, research is being funded by EMR at Saint Mary's University in Halifax to develop low-cost thermal storage units based on commercial grade salts. At higher temperatures, thermal storage units may be an alternative to non-electric heating units for hybrid heating technology, providing a means for peak sharing and load control.

The Canada Centre for Mineral and Energy Technology (CANMET) is assessing the potential application of plasma arc technology in Canada which will aid in the defining the needs for further R&D. This technology provides a high temperature heat source using electricity. Applications include smelting and pyrometallurgy and offer more flexibility than conventional arc technology. Successful development could lead to a major off-oil or gas alternative in instances where electricity availability and rates make the process feasible. Adoption of the technology in the steel industry could reduce the requirement for metallurgical coke. The technology is also capable of further development for eliminating toxic organic wastes.

To increase the options for efficient use of electricity, research is being conducted on both industrial and residential heat pumps. Progress is being made on the development of a residential heat pump for greater efficiency in the Canadian climate. Several industrial heat pumps have been installed and are being monitored to establish credibility for industrial applications.

In some cases electric locomotives can be used to advantage. They offer an off-oil option, reduced maintenance requirements relative to those associated with diesel-electric counterparts and eliminate ventilation problems in tunnels.

In conjunction with the Province of British Columbia and British Columbia Rail, an electrified section of rail which includes two long tunnels and seven grades, is being constructed to serve a coal mine located at Tumbler Ridge. The operation will provide useful data when consideration is given to electrification in other locations.

The choice of an electrified rail link over the more conventional diesel option was influenced by a federal grant. The objective is to demonstrate the application of 50 kV technology which hopefully will be applicable to other rail electrification projects.

Hydro-Québec

R&D expenditures by Hydro-Québec's Research Institute totalled $43.9 million in 1982. Activities reflected the utility's concern with the economy and emphasized new efficient and economic utilization of electricity and marketing.

In 1982, a pilot hydrogen production plant was completed. Hydrogen applications, notably in fuel cells, will now be studied. Other industrial applications included research on plasma technology.

Research on transmission systems focussed on direct current and interconnection technologies. Development work on the proposd 450 kV Des Cantons line, linking Quebec to New England, continued.

Among the R&D initiatives for alternate energy sources, priority has been placed on the EOLE vertical - axis wind turbine and the Tokamak experimental fusion device. These projects are being developed in conjunction with the National Research Council. Preliminary design work and siting studies for EOLE were completed in 1982.

Ontario Hydro

R&D expenditures by Ontario Hydro totalled $66.0 million in 1982. The priorities of the research program reflected Ontario Hydro's new corporate strategy. Emphasis has been placed on research related to economy, reliability and safety in all aspects related to the supply of power. On the demand side, emphasis has been placed on the best use of available energy and resources. The customer orientation of the strategy is aimed at projects which will provide revenues to offset research costs.

In 1982, environmental protection continued to be a major activity. Developmental work on fish exclusion systems continued. These systems will improve generation station reliability.

Acid rain research examined the interaction of clouds and acid emissions. Modelling work on the long-range transport of acid emissions through the atmosphere continued. An instrument assembly was developed to measure the concentration of acid pollutants at ground level.

The Biological Section also examined the biological behaviour of tritium which is produced in small quantities in CANDU reactors. Research on the effects of tritium on plants, soils, and aquatic organisms will aid in the determination of safe concentration limits. Knowledge of the biodynamics of tritium is essential to fusion reactor research.

In April 1982, Ontario Hydro was named project manager for the Canadian Fusion Fuels Technology Project. The project is being conducted by Ontario Hydro, the Ministry of Energy and the National Research Council. The project is aimed at developing Canadian expertise in fusion fuel systems, materials, equipment development and reliability.

Ontario Hydro is participating in a photovoltaic systems evaluation program with the National Research Council. A remote monitor has been located 14 km from the Atikokan coal-fired generating station. The monitor samples air quality and transmits the data to the generating station. The electricity operating the monitor is generated by a 37 square metre photovoltaic array. During sunless periods, electricity is supplied from energy storage batteries.

Saskatchewan Power

R&D expenditures by Saskatchewan Power totalled $2.5 million in 1982. Saskatchewan Power's Research and Development Centre conducts projects related to coal conversion technology, biomass, unconventional energy utilization, and conservation and system operation. Included are studies on coal reactivity, dewatering and beneficiation, transmission line aeolean vibration, digital relaying and transient fault recording, load management, load diversity and the expansion of rural systems to meet electric heating needs.

Manitoba Hydro

Manitoba Hydro, in conjunction with the Government of Manitoba, the University of Manitoba, Teshmont Consultants Inc. and Federal Pioneer Limited has established the Manitoba HVDC Research Centre. The Centre, established in 1982, is directed primarily at analytical and developmental research on HVDC transmission systems and at assisting Canadian industry to realize its potential for the manufacture of HVDC and related equipment. Initial funding has been provided by the Manitoba Government, totalling $3.75 million over the first five years, and by Manitoba Hydro, up to $1.25 million over the same period. If additional financing is required it will be obtained by borrowing. The Centre expects to be self-supporting within the 5-year period ending March 31, 1986.

The first research project, under contract from The Electric Power Research Institute (EPRI), in the United States, involves research on multi-terminal operation of HVDC systems. IREQ and the University of Wisconsin are involved in this research. In addition, a contract for monitoring ion drift and corona on the operational Manitoba Hydro lines has been signed with the Government of Canada for NRC. The Centre will identify and evaluate future research projects.

B.C. Hydro

B.C. Hydro's research and development organization performs chemical, material and electrical research. The corporation also researches wind generation of electricity, geothermal energy, thermography, coal liquifaction and pressurized fluidized bed combustion. In addition, testing is carried out for government agencies and industry in relation to insulating oils, high voltage testing, generator insulation systems, scanning electron microscope tests and non-destructive materials testing.

Electrical research in the research group comprises: distribution and utilization; electronics and control; high voltage; insulation studies and system studies.

B.C. Hydro's research and development expertise seeks to provide a service for adequate, reliable, cost-effective and safe supply of electricity.

Canadian Electrical Association

The CEA's research program totalled to $7.8 million in 1982. These resources were allocated among committees as follows: $3.1 million to the Generation Program; $1.7 million to the Transmission Systems Program; $2.0 million to the Distribution Program; and $1.0 million to Utilization and Conservation. Co-funding of some projects in each division added a further $2.88 million to the total value of the research and development undertaken.

The Generation Committee carries out work in three main areas: fossil and nuclear plants, hydro-electric plants, and alternate energy and energy management. A total of 20 projects were completed during 1982 and 24 new projects were awarded. Among the new projects were studies on sulphur and nitrogen-oxide emissions and transport, acid deposition, simplified methodology for small scale hydro plants, coal fire monitoring, and technical evaluation of large scale wind turbines. 1983 will see the initiation of a new 5-year plan (1983-1988). The excess generating capacity of a number of utilities has changed the emphasis from new plants to the area of existing plant reliability and extension of existing plant life. 1983 projects will concentrate on these areas and stress greater utilization and cost-effectiveness.

The Transmission System Program is aimed at a broad range of research in the areas of overhead and underground transmission. It seeks to improve existing technologies, to meet growing capacity requirements and increasingly strict environmental constraints.

The development of advanced technology for increased utilization of system components is a major area of concern. 14 new projects were initiated in 1982 including work in the areas of metal oxide arresters, conductor vibration damping, non-porcelain synthetic insulators and insulator contamination monitoring.

Due to reduction of forcast demand for electricity, increased emphasis will be given in 1983, to projects which will provide near term returns but the group will continue to recognize the need for long-term goals. Projects will include research in the HVDC area, improved insulators and gas insulated equipment.

The Distribution Program is geared to the identificaion of potential electric distribution system problems and the formulation of appropriate research projects for their solution. Essential ingredients of the program are position papers and state-of-the-art studies, which help make expert advice available for sound definition of the specific R&D solutions required.

Projects fall into the following areas:

- higher voltage surge and fuse protection;
- materials;
- aesthetics and environmental aspects;
- overhead systems;
- safety;
- loading, switchng and overcurrent of underground systems;
- system design;
- reliability;
- automation load control aspects.

In 1982, 24 new projects were initiated including: wood pole in service performance and ground line preservation, industrial pollution and distribution plants, evaluation of U/G distribution cable insulation, AL AL mechanical conductor connectors. In 1983, interest will be focused on distribution system loss reduction, ampacity and loadability of polymeric cables, impact of electric heat conversions, and the increasing problem of cold load pick-up.

The Utilization and Conservation Program emphasis for the consumer is on the efficient end use and conservation of electric energy, and on the reduction in the need for new supply facilities by load management control and development of new combined energy techniques.

The Utilization and Conservation Program is divided into two main areas of activity:

i) that relating to the consumer;

ii) that relating to the utility.

These areas are, of course, highly interactive. With rising energy costs, the efficient end use of energy and conservation is important to investments in these areas. For the utilities, long-term savings will be realized by load control/management and innovative combined energy techniques. Consequently the Program aims to develop energy-efficient applications which will be beneficial both to the consumer and to the utility.

Over 40 research proposals were considered during 1982, under the broad headings of load management, fuel substitution, energy efficiency and consumer attitudes/utility policy. From this number, 15 projects were initiated together with position papers and state-of-the-art studies where there was a need to obtain current knowledge in order to define more precisely future action and research efforts required.

In 1983, division of the committee into action groups will help to streamline and give proper stress to three areas of activity:

i) policy research;

ii) customer end use;

iii) research common to policy and customer end use.

An increase in budget allocation will allow the committee to meet more adequately the extensive range of research and development within its scope. Among the priorities are analysis of energy services; demand and energy use forecasting; water heating; space heating; appliances; variable speed and high efficiency motors; load management; air quality and improved efficiency in all areas.

Placing fuel bundles into N.B. Power's Lepreau nuclear plant.

ENVIRONMENTAL ISSUES

Generation and distribution of electricity affects the environment in a variety of ways. The electric utility industry faces two important environmental issues regarding generation. The first is the relationship between acid emissions from coal-fired plants and acid rain. The second is radioactive waste management.

1 Acid Rain

Significant among environmental problems facing the electric industry are concerns surrounding conventional thermal generation. This problem is linked to the issue of acid rain. The term refers to the problem caused by emissions of sulpher and nitrogen oxides which combine with atmospheric moisture to produce sulphuric acid and nitric acid. These acids return to the ground as acid rain or acid snow.

It also encompasses dry deposition. Dry particles of SO_2 and NO_x fall to the earth and the particles become acidic when combined with surface water. These two processes occur with roughly equal frequency.

The release of pollutants from acid rain results from activities in various industrial and non-industrial sectors. These include transportation, non-ferrous smelting, non-utility and utility boilers.

Approximately 15 per cent of the increased demand for electricity in Canada between 1981 and 1994 will be met by coal-fired generation, a contributor to sulphur dioxide emissions. The additional fuel burned, together with existing coal requirements, could add to the acid rain problem.

Acid rain has far-reaching implications for all aspects of the environment. It alters the ph levels of soil and of water bodies, causing changes in the level and quality of aquatic life and vegetation. While the complexities of acid rain phenomena are not completely understood, the circumstantial evidence linking man-made emissions and environmental loadings is convincing. The deleterious effect of acid on sensitive ecosystems is considered enough to warrant reducing acid causing emissions.

Acid rain is not a localized phenomenon because SO_2 and NO_x are transported over long distances through the atmosphere. There is particulate and gaseous deposition in the vicinity of an emitting source. However, the trend toward building taller stacks to relieve local pollution problems has aggravated regional, interprovincial and international problems.

Approximately 4 million metric tonnes of SO_2 are deposited in Canada annually from sources in the United States and between 500-700 thousand tonnes are deposited in the U.S. from Canadian sources. Approximately 60 per cent of Canadian emissions from east of Manitoba come from non-ferous smelters and about 15 per cent from thermal power stations. The balance is mainly from industrial processes and non-utility fuel use.

In February 1983, a series of U.S.-Canada Working Group reports on transboundary air pollution was published. These focused primarily on acid rain. The bilateral Working Groups were formed under a Memorandum of Intent (MOI) signed by both governments in August, 1980. Groups were composed of Canadian federal and provincial scientists and American scientists from a number of federal agencies. They assembled and analyzed available information on the nature and causes of acid rain and worked on solutions to the problem.

The Working Group reports will be subjected to scientific peer review later in the year. The reports confirm that damage is occurring in areas vulnerable to acid rain and that this is attributable mainly to wet and dry deposition of sulphur compounds.

The reports concur that an environmental loading rate of 20 Kg/Ha/year wet sulphate deposition is related to damage in the vulnerable level. No effect is reported below this loading rate.

Canadian and U.S groups differ on the appropriateness of recommending a loading target of 20 Kg/Ha/year. The U.S groups maintain the recommendation is premature.

The working Group reports examined transport of air pollutants between source region and receptor areas. They show acid rain occurs in eastern North America within and downwind of major source regions of oxides of sulphur and nitrogen. The evidence suggests that much of the acidic deposition in the northeastern United States and eastern Canada is man made. The evidence is the geographical association between the region of the largest North American emissions of sulphur and nitrogen oxides and the regions of the largest wet deposition of sulphur and nitrogen oxides.

The Working Group tried to determine the origin of the sulphur falling on various parts of eastern North America through modelling. However, reliability of current models is uncertain when predicting the results of alternate emission patterns (i.e. the change in deposition that would result from change in emissions). The Working Group on impact assessment recommended further research to assess the economic benefits of controlling acid rain pollutants.

Despite these uncertainties the Canadian members of the Working Group stressed the serious nature of the acid rain problem and the need for regulatory action to prevent further damage.

Canada — U.S. Negotiations

For over a year Canada and the United States have been negotiating a treaty to deal with long range transport of air pollutants, especially those linked to acid rain. These talks are held under the 1980 Memorandum of Intent between the U.S. and Canada. The discussions are expected to continue for at least an additional year due to differing perspectives of the two countries.

In 1982, Canada proposed a 50 per cent reduction in Canadian sulphur dioxide emissions east of Saskatchewan by 1990, contingent upon similar actions in the eastern U.S. The U.S. response has been that this commitment would be premature as it questions the adequacy of the scientific data. Depressed economic conditions also deter U.S. reductions. However the U.S. government will increase acid rain research funds by 28 per cent, to $23 million in 1983. This reflects the U.S. view that more research is needed before increasing controls.

U.S. Congress may make revisions to the U.S. Clean Air Act prior to its reauthorization and this has drawn attention to the acid rain problem. Consideration is being given to possible relaxing of the clean air laws or to possible strengthening of these laws.

In the United States, there exist approximately 87 flue gas desulphurization units, or 'scrubbers', installed on fossil-fired generating units and an additional 22 are currently being installed. Regulations of the Environmental Protection Agency (EPA) require new fossil-fired plants to have scrubbers.

These standards do not apply to existing stations or those converting from oil to coal. This policy is consistent with that of other countries faced with acid rain problems. In these countries, retrofitting scrubbers to older plants or to converted plants is seen as uneconomical.

Response to Acid Rain

In Canada measures are being taken to curb emission levels. The federal and Nova Scotia governments recently announced a $4.1 million pilot project to test fluidized bed combustion of coal as an alternative to scrubbers. The experiment is being conducted at the Nova Scotia Power Corporation's Point Tupper generating station.

Under the National Energy Program, funding for conversions from oil to coal-fired generating stations is contingent upon environmental acceptability. The Governments of Manitoba, Ontario, Quebec and New Brunswick are committed to the 50 per cent in reduction emissions contingent upon similar actions in the eastern U.S. It is within provincial jurisdiction to control emissions. Federal authority exists only over international agreements.

The Ontario Government initiated a program aimed at a 43 per cent emissions reduction by 1990. The program includes controls on contributors such as International Nickel Company (INCO) and Ontario Hydro. The utility is committed to emission reduction using a range of control options and technologies. In addition to purchasing only washed coal, Ontario Hydro blends Canadian and U.S. coal to reduce sulphur dioxide emissions by about 15 per cent. Total utility emissions should be halved by 1990.

In Alberta maximum particulate emission limits have been set. Limits have also been set on ambient ground level concentrations of SO_2, NO_x, and particulates. To comply with the regulations, Alberta Power will install electrostatic precipitators at the Sheerness Station now under construction. Retrofit precipitators will be installed on Battle River units one to four. An electrostatic precipitater has been installed on unit five.

Capital costs of environmental requirements at the two stations totalled approximately $86 million. Operating and maintenance costs for monitoring total approximately $170,000 per annum.

Scientific research into acid rain is carried out by various federal departments in Canada. These include the Departments of the Environment, Fisheries and Oceans, National Health and Welfare and Energy, Mines and Resources. These research and development programs were expanded in 1980 with increases in funding over four years of $10.0 million to Environment, $12.4 million to Fisheries and Oceans, and $3.7 million to Health and Welfare.

These departments contribute to the Federal Long-Range Transport of Air Pollutants (LRTAP) Program. The program has three sections: Scientific Studies, Information Projects and Control Strategies Program Studies. Coordination of the program is provided by the Interdepartmental LRTAP Committee. The program enhances the scientific and technical understanding of LRTAP and acidic precipitation. Expansion of the program is being considered.

Effects of acid rain/LRTAP are being researched simultaneously by the provinces, academic institutions and the private sector. The Federal-Provincial Management Board coordinates the activities of the federal and provincial governments in emission reductions, research and public information.

2. Radioactive Waste Management

Since 1976, Atomic Energy of Canada Ltd. (AECL) has directed a research program on the permanent passive disposal of irradiated fuel waste in stable crystalline rock of the Canadian Shield. Preliminary results from this program indicate nuclear fuel waste can be safely disposed in this manner.

This research is a joint program performed under the terms of the Canada/Ontario agreement of June,1978. Under this agreement Ontario Hydro is responsible for research on storage and transportation of irradiated fuel. A further Federal/Ontario agreement in August 1981, defined the evaluation process leading to acceptance of the proposed disposal concept proposed.

The concept evaluation process consists of a regulatory review, public hearings and governmental decision. Until government approval is obtained for the disposal concept, site selection for an actual disposal facility will be delayed. Approximately 6,000 tonnes of used fuel has been generated, and this material is safely stored using accepted methods at the reactor sites.

The research program receives approximately $30 million per annum in funding. The program includes:

1) generic research and development of technologies for the interim storage and transportation of used fuel;
2) immobilization of used fuel and recycle wastes in containers which provide isolation from ground water;
3) geoscience research to characterise geologic features relevant to selection of future disposal sites;
4) environmental and safety assessment to estimate the effects of storage;
5) transport;
6) immobilization and disposal of nuclear fuel wastes.

An underground research laboratory will be constructed near Whiteshell, Manitoba by 1986. This facility will be used to verify predictions of geological and hydro-geological conditions. It will provide underground space for in situ experiments to verify data from computer models.

The federal government has recently announced new initiatives for the other two categories of Canadian radioactive waste, namely uranium tailings and low-level radioactive waste.

In September 1982, details of a five year $9.5 million federal research program were announced. This program will study the long term effects of uranium tailings, and expedite development of technology to maintain the safety of tailings deposits after closing of the mining operations.

Approximately, 120,000,000 tonnes of uranium tailings have been generated to date, representing 2 per cent of the mining wastes deposited in Canada. This material is subject to monitoring and control of harmful effluents.

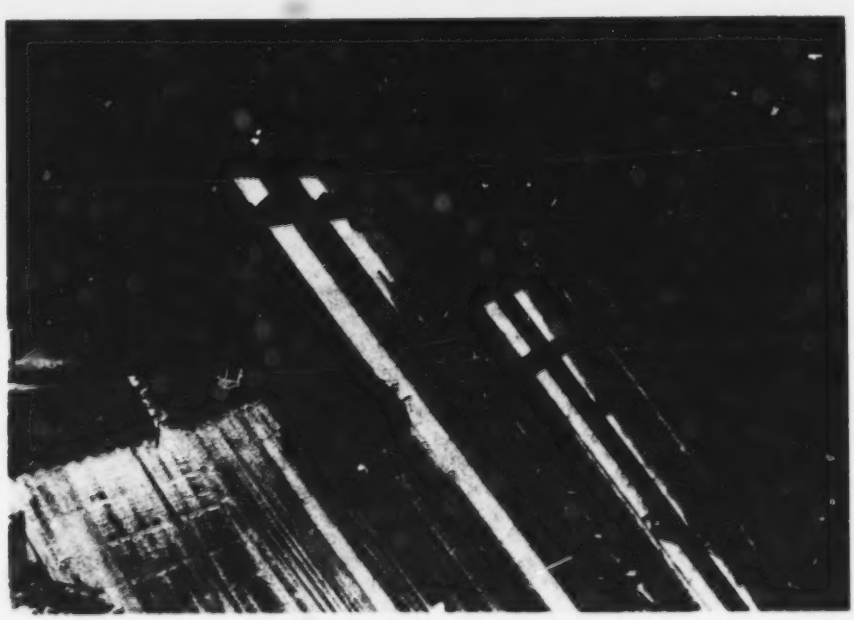
The research program consists of measurement, modelling and disposal technology areas. Measurement will examine operating tailings and systems abondoned 20 years ago for hydrological, geochemical and environmental effects. Modelling will develop and verify predictive scientific procedures to determine future effluents and their health and environmental effects. Disposal technology will examine the effects of different rehabilitation and disposal technologies on long term health and environmental factors. The technologies being considered range from landscaping and revegetation, variations in deposition methods, and deposition in lakes to removal of contaminants.

In October 1982, AECL formed a new office to carry out the federal responsibilities of low-level radioactive waste management. These responsibilities include the completion of remedial work for cleanup of historic waste problems, research and evaluation of options available for disposal, and ensuring that a collection, treatment and safe disposal service is available on a commercial basis. Low-level radioactive waste is produced in research facilities, in hospitals, in industrial plants, and in nuclear electricity generating stations.

Approximately 1,000,000 tonnes of low-level radioactive wastes have been generated in Canada to date. Most wastes of this kind are in safe storage under supervision. Although this storage can be continued for many years, permanent disposal will eventually be required.

Research programs for the management and disposal of the low-level radioactive wastes are being conducted by AECL, Ontario Hydro and Eldorado Resources Limited. The programs seek to reduce the volume and immobilize waste products. They evaluate the potential use of three types of disposal facilities — sanitary landfill, engineered facilities at shallow depth and deep geological facilities.

With these three programs the federal government is addressing all aspects of the management and disposal of radioactive waste in Canada. Much work remains before a complete operating system is in place. The cooperation and support of provincial and municipal governments, industry and the public will be required to reach that goal.



Construction of a concrete dam at B.C. Hydro's Revelstoke Hydro project.

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For readers requiring additional statistical information, the following publications are issued in English and French by the Manufacturing and Primary Industries Division, Statistics Canada. Copies may be ordered from:

Statistics Canada
Ottawa, Ontario
Canada
K1A 0T6

Electric Power Statistics, Volume I - Annual Electric Power Survey of Capability and Load (Catalogue No. 57-204)

Presents the results of the annual electric power survey of capability and load and covers all producers of electrical energy in Canada which generate or will generate 20 million kWh per annum or more during the forecast period.

Electric Power Statistics, Volume II - Annual Statistics (Catalogue No. 57-202)

Includes various statistics, on an annual basis, for electric utilities and industrial establishments including installed capacity, generation, supply and disposal, number of customers, revenue, energy transfers, domestic and farm service, and transmission mileage. Statistics on fuels, employees, wages and salaries, assets and liabilities, income account, taxes and capital and repair expenditures are also included for electric utilities.

Electric Power Statistics, Volume III - Inventory of Prime Mover and Electric Generating Equipment (Catalogue No. 57-206)

Provides a detailed listing of prime mover and generating equipment above 500 kW, on an annual basis.

Electric Power Statistics, Monthly (Catalogue No. 57-001)

Presents, on a monthly basis, preliminary electrical energy statistics.

Electricity Bills for Domestic, Commercial and Small Power Service (Catalouge No. 57-203)

Based on the rate schedules supplied by the power companies and municipalities responsible for the distribution of electrical energy in the cities and towns covered in an annual survey. Monthly bills are computed to show the revenue according to the distributors from the sale of definite quantities of electricity used for specific purposes.

Quarterly Report on Energy-Supply Demand in Canada (Catalogue No. 57-003)

Energy balance sheets in both natural units and terajoules for fuel types by region. Each balance sheet shows data on production, imports, exports, interregional movements, conversion from one energy form to another, and consumption by consuming sectors.

The following publications are available from distributors of Canadian government publications, or from the OECD Publications Office, 2 rue André-Pascal, 75 Paris 16e, France.

Organization for Economic Cooperation and Development, Survey by the Energy Division, Annual Survey of Electric Power Equipment, Situation and Prospects.

Combines the results of two studies carried out by the OECD:

- Survey of the Energy Division in the development of capital eqipment in the electricity supply industry and its technical characteristics (Part One)
- Survey of the Special Committee for Machinery on the trends of deliveries, orders on hand and production capacity of European manufacturers of heavy equipment for power stations (Part Two)

These two complementary surveys show the situation as of January 1st and give an indication of trends for the next 5 years.

Organization for Economic Cooperation and Development, Energy Division, the Electricity Supply Industry.

Annual general review of the electricity supply industry in OECD countries in the last 2 years and provides an outlook for the following five years.

Organization for Economic Cooperation and Development, Economic Statistics and National Accounts Division, Statistics of Energy

Presents annually a set of basic statistics on production, trade consumption, etc. for each source of energy, following a standard patterm so that they are presented in consolidated and comparable form.

OECD Energy Statistics 1972/1981
OECD Energy Balances 1971/1981
OECD Oil and Gas Statistics 1980/1981

In addition, more detailed information on individual foreign countries can be obtained by contacting individual electric utilities or government agencies.

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Table A1 Installed Capacity and Electric Energy Consumption in Canada, 1920-1982

Year	INSTALLED CAPACITY					Electric Energy Consumption	Average Demand	Peak Demand	Generation Reserve		Load Factor
	Thermal										
	Conventional	Nuclear	Sub-Total	Hydro	Total						
	(MW)					(a) (GWh)	(b) (MW)	(c) (MW)	(MW)	(d) %	(e) %
1920	300	—	300	1700	2000	—	—	—	—	—	—
1930	400	—	400	4300	4700	19468	2222	—	—	—	—
1940	500	—	500	6200	6700	33062	3774	—	—	—	—
1950	900	—	900	8900	9800	55037	6283	—	—	—	—
1955	2100	—	2100	12600	14700	81000	9247	12536	2164	15	74
1960	4392	—	4392	18657	23049	109302	12477	17264	5785	25	72
1961	5072	—	5072	19019	24091	110950	12666	18353	5738	24	69
1962	5609	20	5629	19338	24967	116135	13257	18937	6030	24	70
1963	6180	20	6200	20101	26301	121510	13871	20783	5518	21	67
1964	6694	20	6714	20313	27027	133949	15291	22516	4511	17	68
1965	7557	20	7577	21771	29348	144165	16457	24167	5181	18	68
1966	8307	20	8327	22438	30765	156956	17917	25921	4844	16	69
1967	9373	240	9613	23353	32966	165812	18928	27812	5154	16	68
1968	10711	240	10951	24957	35908	176841	20187	30300	5608	16	67
1969	12321	240	12561	27031	39592	189522	21635	32092	7500	19	67
1970	14287	240	14527	28298	42826	202337	23098	34592	8234	19	67
1971	14504	1570	16075	30601	46676	212882	24302	35720	10956	23	68
1972	15318	2126	17444	32500	49944	231557	26433	38921	11023	22	68
1973	17711	2400	20111	34266	54376	249298	28459	42699	11677	21	67
1974	18085	2666	20751	36779	57530	266956	30747	42528	15002	26	72
1975	21404	2666	24070	37282	61352	265955	30360	46187	15165	25	66
1976	23039	3466	26505	39488	65993	284829	32515	49537	16456	25	66
1977	24699	5066	29765	40810	70575	299673	34209	52001	18574	26	66
1978	26154	5866	32020	41898	73918	316435	36123	54106	19812	27	67
1979	27353	5866	33219	44009	77228	323465	36925	55699	21529	28	66
1980	27853	5866	33719	47919	81634	340069	38821	59170	22464	28	66
1981	28493	5600	34093	49216	83308	346333r	39536r	59237r	24071r	29r	67
1982*	28522	6280	34802	49975	84777	344083	39279	65415	19362	23	60

(a) 1920-55: figures are approximate, computed using actual Statistics Canada data for stations generating energy for sale to which have been added estimates for stations generating entirely for own use. 1920-55 Canadian Energy Prospects (Royal Commission on Canada's Economic Prospects) John Davis, 1957. 1956-82, Statistics Canada Publication 57-202.

(b) Average Demand = Energy Consumption ÷ 8 760 (hrs/yr).

(c) Statistics Canada Publications 57-204.

(d) Generation Reserve Data is based on capacity. These figures differ from those presented by Statistics Canada Publication 57-204 as latter are based on capability.

(e) Load Factor = Average Demand ÷ Peak Demand.

** Preliminary Data.*

r Revised Figures.

Table A2 Installed and Proposed Generating Capacity, 1982 (MW)

Province	Hydro	Nuclear	Conventional Thermal*	Total	% of Canadian Total
Newfoundland	6210	—	748	6958	8.2
Prince Edward Island	—	—	118	118	**
Nova Scotia	363	—	1669	2032	2.4
New Brunswick	901	680	1891	3472	4.1
Quebec	21354	—	1160	22514	26.6
Ontario	7090	5600	13257	25947	30.6
Manitoba	3641	—	501	4142	4.9
Saskatchewan	576	—	1781	2356	2.8
Alberta	734	—	5467	6201	7.3
British Columbia	9000	—	1763	10762	12.7
Yukon	58	—	37	95	**
Northwest Territories	47	—	131	178	**
Canada Total at Dec. 31, 1982***	49975	6280	28522	84777	—
Percent of Total Capacity, End 1982	59	7	34	100	—
Net additions During 1982***	608	680	181	1469	—
Planned additions During 1983	1685	1201	732	3618	—

* *Details provided in Table A3. Conventional thermal includes steam, gas turbine, internal combustion.*
** *Less than 0.5%.*
*** *Preliminary Data.*

Table A3 Conventional Thermal Capacity by Principal Fuel Type. Preliminary Figures as of December 31, 1982

Province	Steam					Gas Turbine			Internal Combustion			All Conventional Thermal				
	Coal	Oil	Gas	Other*	Total	Oil	Gas	Total	Oil	Gas	Total	Coal	Oil	Gas	Other*	Total
						(MW)										
Newfoundland	—	503	—	—	503	170	—	170	75	—	75	—	748	—	—	748
Prince Edward Island	—	70	—	—	70	41	—	41	7	—	7	—	118	—	—	118
Nova Scotia	637	826	—	—	1 463	205	—	205	1	—	1	637	1 032	—	—	1 669
New Brunswick	285	1 555	—	23	1 863	23	—	23	5	—	5	285	1 583	—	23	1 891
Quebec	—	636	—	13	649	363	—	363	148	—	148	—	1 147	—	13	1 160
Ontario	9 149	2 330	1 318	84	12 881	366	—	366	4	6	10	9 149	2 700	1 324	84	13 257
Manitoba	419	—	4	24	447	24	—	24	31	—	31	419	55	4	24	501
Saskatchewan	1 475	—	163	21	1 659	—	104	104	18	—	18	1 475	18	267	21	1 781
Alberta	3 673	66	1 284	75	5 098	—	327	327	12	30	42	3 673	78	1 641	75	5 467
British Columbia	—	40	969	274	1 283	188	151	339	123	18	141	—	351	1 138	274	1 763
Yukon	—	—	—	—	—	—	—	—	37	—	37	—	37	—	—	37
N.W.T.	—	1	—	—	1	—	—	—	130	—	130	—	131	—	—	131
CANADA	15 638	6 027	3 738	514	25 916	1 308	582	1 962	591	54	644	15 638	7 998	4 374	514	28 522

** Mainly wood wastes and black liquor.*

Table A4 Electrical Energy Production by Principal Fuel Type, Preliminary Figures 1982

Province	Conventional Thermal							Percentage Generated By	
	Coal*	Oil*	Gas*	Total	Nuclear	Hydro	Total	Percentage of Total Generation	Utilities	Industrial Establishments
					(GWh)					
Newfoundland	—	1 155	—	1 155	—	43 109	44 264	11 8	98 9	1 1
Prince Edward Island	—	35	—	35	—	—	35	.01	100 0	.0
Nova Scotia	2 790	2 747	—	5 537	—	1 044	6 581	1.8	95.7	4.3
New Brunswick	1 275	4 251	—	5 526	254	2 614	8 394	2 2	92 7	7 3
Quebec	—	252	—	252	—	99 768	100 019	26 6	82 7	17 3
Ontario	34 542	396	2 084	37 022	36 161	37 480	110 663	29 5	96 4	3 6
Manitoba	209	59	15	283	—	20 495	20 779	5 5	99 7	0 3
Saskatchewan	6 640	112	731	7 483	—	2 360	9 843	2 6	96 0	4 0
Alberta	19 397	245	4 911	24 553	—	1 590	26 143	7 0	94 3	5.7
British Columbia	—	930	858	1 788	—	46 131	47 919	12 8	76 5	23 5
Yukon	—	77	—	77	—	269	346	0 1	100 0	0
Northwest Territories	—	188	—	188	—	275	463	0 1	94 5	5 5
CANADA	64 853	10 447	8 599	83 898	36 415	255 136	375 449	100 0	90 4	9 6

** Estimated values.*
SOURCE: Statistics Canada.

Table A5 Provincial Electricity Imports and Exports

Province	Year	Interprovincial Trade			International Trade			Total Net Exports
		Exports	Imports	Net Exports	Exports	Imports	Net Exports	
					(GWh)			
Newfoundland	1982	35 777	—	35 777	—	—		35 777
	1981	35 941	—	35 941	—	—	—	35 941
	1980	37 829	—	37 829	—	—	—	37 829
Prince Edward Island	1982	—	476	-476	—	—	—	-476
	1981	—	480	-480	—	—	—	-480
	1980	—	388	-388	—	—	—	-388
Nova Scotia	1982	123	216	-83	—	—	—	-83
	1981	111	303	-192	—	—	—	-192
	1980	227	173	-54	—	—	—	54
New Brunswick	1982	692	3 746	-3 054	3 029	71	2 958	-95
	1981	784	3 829	-3 045	3 246	54	3 193	148
	1980	561	3 902	-3 341	3 871	54	3 816	475
Quebec	1982	9 386	35 833	-26 447	8 530	7	8 523	-17 924
	1981	10 211	35 999	-25 788	8 314	7	8 307	-17 481
	1980	9 429	37 874	-28 445	8 107	6	8 101	-20 344
Ontario	1982	60	6 845	-6 785	11 168	403	10 765	3 980
	1981	58	7 658	-7 600	11 310	342	10 968	3 368
	1980	45	7 302	-7 257	11 314	249	11 066	3 809
Manitoba	1982	2 460	1 088	1 372	5 255	214	5 041	6 413
	1981	2 469	1 054	1 415	3 681	194	3 487	4 902
	1980	3 127	950	2 117	3 529	192	3 337	5 514
Saskatchewan	1982	1 087	1 388	-301	60	31	29	-272
	1981	1 057	1 305	-248	—	—	—	-248
	1980	955	1 579	-624	—	—	—	-624
Alberta	1982	189	447	-258	—	2	-2	-261
	1981	261	168	92	—	2	-2	90
	1980	385	105	280	—	2	-2	278
British Columbia	1982	444	189	255	6 171	2 119	4 052	4 307
	1981	165	261	-96	8 821	897	7 924	7 828
	1980	100	385	-285	3 354	2 437	917	632
Yukon	1982	—	—	—	—	—	—	—
	1981	—	—	—	—	—	—	—
	1980	—	—	—	—	—	—	—
N.W.T.	1982	—	—	—	—	—	—	—
	1981	—	—	—	—	—	—	—
	1980	—	—	—	—	—	—	—
CANADA	1982	—	—	—	34 214	2 848	31 366	31 366
	1981	—	—	—	35 372	1 496	33 876	33 876
	1980	—	—	—	30 174	2 940	27 234	27 234

Table A6 Generation Capacity by Type

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
			(MW)				
NEWFOUNDLAND							
Total End 1981	502.60	170.39	75.25	—	748.24	6210.26	6958.50
Additions 1982	—	—	—	—	—	—	—
Total End 1982	502.60	170.39	75.25	—	748.24	6210.26	6958.50
Additions Proposed							
1983	—	—	—	—	—	90.62	90.62
1984	—	—	—	—	—	—	—
1985	—	—	—	—	—	127.00	127.00
1986	—	25.00	—	—	25.00	—	25.00
Total End 1986	502.60	195.39	75.25	—	773.24	6427.88	7201.12
PRINCE EDWARD ISLAND							
Total End 1981	70.50	40.85	6.89	—	118.24	—	118.24
Additions 1982	—	—	—	—	—	—	—
Total End 1982	70.50	40.85	6.89	—	118.24	—	118.24
Additions Proposed							
1983	—	—	—	—	—	—	—
Total End 1983	70.50	40.85	6.89	—	118.24	—	118.24
NOVA SCOTIA							
Total End 1981	1463.28	205.00	0.60	—	1668.88	359.90	2028.78
Additions 1982	—	—	—	—	—	3.50	3.50
Total End 1982	1463.28	205.00	0.60	—	1668.88	363.40	2032.28
Additions Proposed							
1983	—	—	—	—	—	22.50	22.50
1984	150.00	—	—	—	150.00	—	150.00
1985	150.00	—	—	—	150.00	—	150.00
Total End 1985	1763.28	205.00	0.60	—	1968.88	385.90	2354.78
NEW BRUNSWICK							
Total End 1981	1862.63	23.38	4.84	—	1890.85	900.93	2791.78
Additions 1982	—	—	—	680.00	680.00	—	680.00
Total End 1982	1862.63	23.38	4.84	680.00	2570.85	900.93	3471.78
Additions Proposed							
1983	—	—	—	—	—	—	—
Total End 1983	1862.63	23.38	4.84	680.00	2570.85	900.93	3471.78
QUEBEC							
Total End 1981	648.75	362.88	144.59	—	1156.22	20767.86	21924.08
Additions 1982	—	—	3.36	—	3.36	586.57	589.93
Total End 1982	648.75	362.88	147.95	—	1159.58	21354.43	22514.01
Additions Proposed							
1983	—	—	—	685.00	685.00	1536.00	2221.00
1984	—	—	—	—	—	2243.00	2243.00
1985	—	—	—	—	—	586.00	586.00
1986	—	—	—	—	—	—	—
1987	—	—	—	—	—	—	—
1988	—	—	—	—	—	—	—
1989	—	—	—	—	—	988.00	988.00
1990	—	—	—	—	—	510.00	510.00
1991	—	—	—	—	—	1275.00	1275.00
1992	—	—	—	—	—	765.00	765.00
Total End 1992	648.75	362.88	147.95	685.00	1844.58	29257.43	31102.01

Table A6 (Continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
				(MW)			
ONTARIO							
Total End 1981	12 732.38	337.72	10.02	5 600.00	18 680.12	7 072.28	25 752.40
Additions 1982	149.00	28.00	—	—	177.00	18.00	195.00
Total End 1982	12 881.38	365.72	10.02	5 600.00	18 857.12	7 090.28	25 947.40
Additions Proposed							
1983	—	28.00	—	516.00	544.00	36.00	580.00
1984	206.00	—	—	1 788.00	1 994.00	—	1 994.00
1985	—	42.00	—	1 272.00	1 314.00	—	1 314.00
1986	—	—	—	756.00	756.00	—	756.00
1987	—	—	—	756.00	756.00	—	756.00
1988	—	14.00	—	881.00	895.00	—	895.00
1989	—	—	—	881.00	881.00	—	881.00
1990	—	—	—	—	—	—	—
1991	—	—	—	881.00	881.00	—	881.00
1992	—	—	—	881.00	881.00	—	881.00
Total End 1992	13 087.38	449.72	10.02	14 212.00	27 759.12	7 126.28	34 885.40
MANITOBA							
Total End 1981	447.00	23.80	30.60	—	501.40	3 641.10	4 142.50
Additions 1982	—	—	—	—	—	—	—
Total End 1982	447.00	23.80	30.60	—	501.40	3 641.10	4 142.50
Additions Proposed							
1992	—	—	—	—	—	255.00	255.00
1993	—	—	—	—	—	637.50	637.50
1994	—	—	—	—	—	382.50	382.50
1996	—	—	—	—	—	96.00	96.00
1997	—	—	—	—	—	288.00	288.00
Total End 1997	447.00	23.80	30.60	—	501.40	5 300.10	5 801.50
SASKATCHEWAN							
Total End 1981	1 658.96	103.92	18.10	—	1 780.98	575.50	2 356.48
Additions 1982	—	—	—	—	—	—	—
Total End 1982	1 658.96	103.92	18.10	—	1 780.98	575.50	2 356.48
Additions Proposed							
1983	300.00	—	—	—	300.00	—	300.00
1984	—	—	—	—	—	—	—
1985	—	—	—	—	—	84.00	84.00
1986	—	—	—	—	—	168.00	168.00
Total End 1986	1 958.96	103.92	18.10	—	2 080.98	827.50	2 908.48
ALBERTA							
Total End 1981	5 098.01	327.30	41.53	—	5 466.84	733.70	6 200.54
Additions 1982	—	—	—	—	—	—	—
Total End 1982	5 098.01	327.30	41.53	—	5 466.84	733.70	6 200.54
Additions Proposed							
1983	400.00	—	—	—	400.00	—	400.00
1984	400.00	—	—	—	400.00	—	400.00
1985	380.00	—	—	—	380.00	—	380.00
1986	780.00	—	—	—	780.00	—	780.00
1987	400.00	—	—	—	400.00	—	400.00
1988	400.00	—	—	—	400.00	—	400.00
1989	400.00	—	—	—	400.00	—	400.00
Total End 1989	8 258.01	327.30	41.53	—	8 626.84	733.70	9 360.54

Table A6 (Continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
			(MW)				
BRITISH COLUMBIA							
Total End 1981	1 282.79	339.20	140.61	—	1 762.60	8 999.62	10 762.22
Additions 1982	—	—	—	—	—	—	—
Total End 1982	1 282.79	339.20	140.61	—	1 762.60	8 999.62	10 762.22
Additons Proposed							
1983	—	—	—	—	—	—	—
1984	—	—	—	—	—	1 843.00	1 843.00
1985	—	—	—	—	—	—	—
1986	—	—	—	—	—	—	—
1987	—	—	—	—	—	—	—
1988	—	—	—	—	—	—	—
1989	—	—	—	—	—	—	—
1990	—	—	—	—	—	—	—
1991	—	—	—	—	—	750.00	750.00
1992	—	—	—	—	—	290.00	290.00
1993					—	70.00	70.00
Total End 1993	1 282.79	339.20	140.61	—	1 762.60	11 952.62	13 715.22
YUKON							
Total End 1981	—	—	37.17	—	37.17	58.14	95.31
Additions 1982	—	—	—	—	—	—	—
Total End 1982	—	—	37.17	—	37.17	58.14	95.31
Additions Proposed							
1983	—	—	—	—	—	—	—
1984	—	—	—	—	—	20.00	20.00
Total End 1984	—	—	37.17	—	37.17	78.14	115.31
NORTHWEST TERRITORIES							
Total End 1981	0.60	—	129.62	—	130.22	47.36	177.58
Additions 1982	—	—	0.60	—	0.60	—	0.60
Total End 1982	0.60	—	130.22	—	130.82	47.36	178.18
Additions Proposed							
1983	—	—	3.89	—	3.89	—	3.89
1984	—	—	0.04	—	0.04	—	0.04
Total End 1984	0.60	—	134.15	—	134.75	47.36	182.11
CANADA							
Total End 1981	25 767.49	1 934.44	639.83	5 600.00	33 941.76	49 366.65	83 308.41
Additions 1982	149.00	28.00	3.96	680.00	680.96	608.07	1 469.03
Total End 1982	25 916.49	1 962.44	643.79	6 280.00	34 802.72	49 974.72	84 777.44
Additions Proposed							
1983	700.00	28.00	3.89	1 201.00	1 932.89	1 685.12	3 618.01
1984	756.00	—	0.04	1 788.00	2 544.04	4 106.00	6 650.04
1985	530.00	42.00	—	1 272.00	1 844.00	797.00	2 641.00
1986	780.00	25.00	—	756.00	1 561.00	168.00	1 729.00
1987	400.00	—	—	756.00	1 156.00	—	1 156.00
1988	400.00	14.00	—	881.00	1 295.00	—	1 295.00
1989	400.00	—	—	881.00	1 281.00	988.00	2 269.00
1990	—	—	—	—	—	510.00	510.00
1991	—	—	—	881.00	881.00	2 025.00	2 906.00
1992	—	—	—	881.00	881.00	1 310.00	2 191.00
1993	—	—	—	—	—	707.50	707.50
1994	—	—	—	—	—	382.50	382.50
1995	—	—	—	—	—	—	—
1996	—	—	—	—	—	96.00	96.00
1997	—	—	—	—	—	288.00	288.00
Total End 1997	29 882.49	2 071.44	647.72	15 577.00	48 178.65	63 037.84	111 216.49

Table A7 Installed Generating Capacity Expansion in Canada by Station. Major 1982 Additions and Projected 1983-1997

Province	Station	Type*	Additions in 1982 (MW)	Year	Additions Proposed (MW)	Status	Proposed plant capacity (MW)
Newfoundland							
	Upper Salmon	H		1983	84.00	I	84.00
	Topsail	H		1983	2.25	C	2.25
	Lawn	H		1983	0.65	C	0.65
	Morris	H		1983	1.07	C	1.07
	Lookout Brook	H		1983	2.65	C	2.65
	Cat Arm	H		1985	2 x 63.50	C	127.00
	Port aux Basques	GT		1986	25.00	P	25.00
Nova Scotia							
	Fourth Lake	H		1983	2.5	C	2.50
	Gisborne Canal	H	3.5			I	3.50
	Annapolis Royal	H		1983	20.0	C	20.00
	Lingan	S(C)		1984	150.0	C	
				1985	150.0	P	600.00
New Brunswick							
	Point Lepreau	N	680			I	680.00
Quebec							
	Beauharnois (net)	H	9.45			I	1 593.00
	Delaney	H		1990	2 x 255	P	
				1991	5 x 255	P	
				1992	3 x 255	P	2 550.00
	Gentilly 2	N		1983	685	C	685.00
	La Grande -						
	LG-3	H	3 x 192			I	
				1983	8 x 192	C	
				1984	192	C	2 304.00
	LG-4	H		1984	7 x 293	C	
				1985	2 x 293	C	2 637.00
	Manic 5	H		1989	4 x 247	C	2 280.00
	Various Locations	H	1.12			I	
	Various Locations	IC	3.36			I	
Ontario							
	Atikokan	S(C)		1984	206	C	206.00
	Bruce B	N		1984	756	C	
				1985	756	C	
				1986	756	C	
				1987	756	C	
		GT	2 x 14	1983	2 x 14	I	3 080.00
	Darlington	N		1988	881	C	
				1989	881	C	
				1991	881	C	
				1992	881	C	
		GT		1985	3 x 14	P	
				1988	14	P	3 580.00
	Pickering B	N		1983	516	C	
				1984	2 x 516	C	
				1985	516	C	2 106.00
	St. Mary's	H	18	1983	2 x 18	I	54.00
	Thunder Bay	S(C)	149			I	447.00

Table A7 (Continued)

Province	Station	Type*	Additions in 1982	Year	Additions Proposed	Status	Proposed plant capacity
			(MW)		(MW)		(MW)
Manitoba							
	Limestone	H		1992	2 x 127 5	P	
				1993	5 x 127 5	P	
				1994	3 x 127 5	P	1 275 00
	Wuskwatim	H		1996	96	P	
				1997	3 x 96	P	384 00
Saskatchewan							
	Nipawin	H		1985	84	C	
				1986	2 x 84	C	252 00
	Poplar River	S(C)		1983	300	C	600 00
Alberta							
	Genesee	S(C)		1986	400	C	
				1987	400	C	800 00
	Keephills	S(C)		1983	400	C	
				1984	400	C	
				1988	400	P	
				1989	400	P	1 600 00
	Sheerness	S(C)		1985	380	C	
				1986	380	C	760 00
British Columbia							
	Keenleyside	H		1992	2 x 70	P	
				1993	1 x 70	P	210 00
	Peace Site C	H		1991	5 x 150	P	
				1992	1 x 150	P	900 00
	Revelstoke	H		1984	4 x 460 75	C	1 843 00
Yukon							
	Whitehorse	H		1984	20	C	

Legend

Hydro	*H*
Steam (Coal)	*S(C)*
Steam (Gas)	*S(G)*
Nuclear	*N*
Internal Combustion	*IC*
Gas Turbine	*GT*
Wind	*W*
Installed	*I*
Under construction	*C*
Planned	*P*

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Canada

Couverture

Construction d'une enceinte de confinement pour la centrale nucléaire de Darlington de l'Hydro-Ontario, cette enceinte doit éliminer toute émanation de gaz radioactifs à l'intérieur de la centrale

Photos gracieusete de
Hydro-Quebec
TransAlta Utilities
Nova Scotia Power Corporation
Hydro-Ontario
B C Hydro
Edmonton Power
Manitoba Hydro

L'énergie électrique au Canada 1982

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Secteur de la politique de l'énergie
Ministère de l'Énergie, des Mines et des Ressources

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DÉFINITIONS ET ABRÉVIATIONS

Capacité: La quantité théorique d'énergie qu'une installation peut produire ou livrer à un moment déterminé. Ainsi, la capacité de production installée ou puissance installée d'une entreprise est la quantité d'énergie maximale qu'elle peut produire à un moment déterminé.

Puissance: Énergie électrique fournie par unité de temps et ordinairement mesurée en kilowatts (kW).

Production: Énergie électrique produite, ordinairement mesurée en kilowattheures (KWh).

Puissance:

kW — kilowatts	
MW — mégawatts =	1 000 kW
GW — gigawatts =	1 000 000 kW
TW — térawatts =	1 000 000 000 kW

Énergie:

kWh — kilowattheures	
MWh — mégawattheures =	1 000 kWh
GWh — gigawattheures =	1 000 000 kWh
TWh — térawattheures =	1 000 000 000 kWh

Tension: kV — kilovolts

CONSOMMATION, PRODUCTION ET CAPACITÉ DE PRODUCTION

Consommation

En 1982, la demande d'électricité a diminué de 0,6 % au Canada pour passer à 344 083 GWh (voir le Tableau 1). Comme en 1981, ce fléchissement de la demande est attribuable au ralentissement de l'économie. Par contre, la légère diminution de la demande d'électricité tranche avec la baisse de 4,8 % du produit national brut réel (P.N.B.) auquel la demande a toujours été étroitement liée. Cette conjoncture montre bien que l'indice de consommation d'électricité par dollar de P.N.B. est toujours en hausse.

Le Tableau 2 effectue une comparaison entre l'augmentation de la demande dans les provinces et la moyenne nationale. On constate qu'au Manitoba et en Alberta le pourcentage d'augmentation de la demande est supérieur à la moyenne nationale: 6,6 % pour le Manitoba et 3,6 % pour l'Alberta. Cette augmentation est attribuable à la rigueur inhabituelle de l'hiver au Manitoba et à l'emploi accru de pompes électriques dans les pipelines albertains.

Depuis 1971, le profil général de la consommation est demeuré à peu près le même, exception faite de quelque variations sectorielles. Le secteur industriel reste le plus gros consommateur; les secteurs résidentiel et commercial occupent les deuxième et troisième rangs respectivement. (Voir le Tableau 3.)

Production

La production totale d'électricité a diminué de 1,2 % pour passer à 375 449 GWh en 1982. L'énergie hydraulique assure 68 % de ce total, l'énergie nucléaire 10 %, le reste, 22 %, provenant de sources thermiques classiques. Cette diminution est la conséquence d'une baisse de la consommation intérieure de l'ordre de 0,6 %, et d'une autre baisse de 7,4 % des exportations nettes vers les États-Unis.

Puissance installée

Selon les estimations, la puissance installée a augmenté de 1 469 MW pour passer à 84 777 MW en 1982, soit une hausse de 1,8 % par rapport

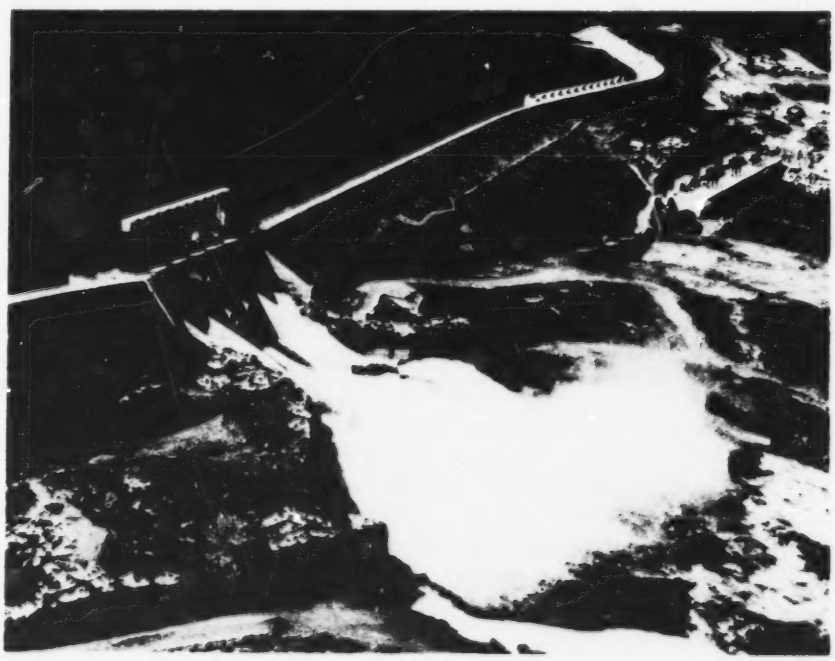
Tableau 1. Sommaire statistique: totaux pour le Canada, 1981-1982

	1982	1981	Variation en %	Renvoi à un tableau*
Demande totale d'électricité (GWh)	344 083	346 333	-0.65	2
Production totale (GWh)	375 449	380 209	-1.25	2, A4
de source: hydro-électrique	255 136	263 472	-3.16	A4
nucléaire	36 415	37 799	-3.66	A4
thermique classique	83 898	78 938	6.28	A4
Total des exportations nettes (GWh)	31 366	33 876	-7.41	2, A5
total des importations	2 848	1 496	90.37	A5
total des exportations	34 214	35 372	-3.27	A5
Puissance totale au 31 décembre (MW)[1]	84 777	83 308	1.76	A2
hydro-électrique	49 975	49 367	1.23	A2
nucléaire	6 280	5 600	12.14	A2
thermique classique	28 522	28 341	0.64	A2, A3
Total des augmentations nettes de puissance au cours de l'année (MW)	1 469	2 256	-34.88	4
hydro-électrique	608	1 679	-63.79	A6, A7
nucléaire	680	—	**	A6, A7
thermique classique	181	577	-68.63	A6, A7

[1] Ne tient pas compte de données confidentielles qui ne sont pas disponibles par province. Total des données confidentielles pour 1981: 438 MW

** Les tableaux indiqués fournissent des données par province*

*** Indéterminée*



L'évacuateur de crues au projet LG-3 (2304 MW) de l'Hydro-Québec.

à 1981. Les augmentations se chiffrent à 608 MW pour les centrales hydro-électriques, 181 MW pour les centrales thermiques classiques et 680 MW pour les centrales nucléaires, soit des augmentations respectives de 42 %, 12 % et 46 %. Des renseignements détaillés sont donnés au Tableau 4.

L'année 1982 a été marquée par la fin des travaux de construction de la première centrale nucléaire de la Commission d'énergie électrique du Nouveau-Brunswick, à Pointe Lepreau. Cette centrale de 680 MW, qui avait déjà commencé à produire de l'électricité en septembre 1982, a été officiellement inaugurée en janvier 1983.

La Figure 1 donne un aperçu détaillé de la puissance installée par source d'énergie et par région; la Figure 2 indique le type de puissance installée et la production d'électricité par principales sources d'énergie dans chaque province et dans les territoires; enfin, la Figure 3 fournit un profil historique de la puissance installée par secteur.

Tableau 2. Offre et demande provinciales d'électricité (GWh)

Province	Année	Production	Exportations nettes	Demande provinciale totale	Augmentation de la demande en 1981-1982	Augmentation annuelle cumulée pour la période 1977-1982	Augmentation annuelle cumulée pour la période 1972-1982
						(%)	
Terre-Neuve	1982	44 264	35 777	8 487	-3.84	1.82	5.67
	1981	44 767	35 941	8 826			
Île-du-Prince-Edouard	1982	35	-476	511	0.00	2.48	5.19
	1981	31	-480	511			
Nouvelle-Écosse	1982	6 581	-83	6 664	-1.54	1.62	3.61
	1981	6 576	-192	6 768			
Nouveau-Brunswick	1982	8 394	-95	8 489	-4.04	1.36	4.47
	1981	8 994	148	8 846			
Québec	1982	100 019	-17 924	117 943	-2.25	2.97	4.45
	1981	103 175	-17 481	120 656			
Ontario	1982	110 663	3 980	106 683	-0.93	1.59	3.04
	1981	111 056	3 368	107 688			
Manitoba	1982	20 779	6 413	14 366	6.56	3.30	3.48
	1981	18 384	4 902	13 482			
Saskatchewan	1982	9 843	-272	10 115	1.85	4.26	5.14
	1981	9 683	-248	9 931			
Alberta	1982	26 143	-261	26 404	3.63	8.60	7.89
	1981	25 570	90	25 479			
Colombie-Britannique	1982	47 919	4 307	43 612	0.82	2.55	3.29
	1981	51 087	7 828	43 258			
Yukon	1982	346	—	346	-10.13	-1.23	3.60
	1981	385	—	385			
Territoires du Nord-Ouest	1982	463	—	463	-7.77	0.35	3.05
	1981	502	—	502			
CANADA	1982	375 449	31 366	344 083	-0.65	2.78	4.04
	1981	380 209	33 876	346 333			

Tableau 3. Demande totale d'électricité au Canada, par secteur, 1978-1981

	1978		1979		1980		1981	
	(GWh)	(%)	(GWh)	(%)	(GWh)	(%)	(GWh)	(%)
Résidentiel et agricole	86 106	27	87 638	27	92 669	27	96 052	28
Commercial	68 721	22	72 384	22	73 450	22	75 709	22
Industriel	161 608	51	163 443	51	173 949	51	174 572	50
TOTAL	316 435	100	323 465	100	340 068	100	346 333	100

Source: Statistique Canada, 57-202

Figure 1

Capacité et production selon la région et la source d'énergie, 1982

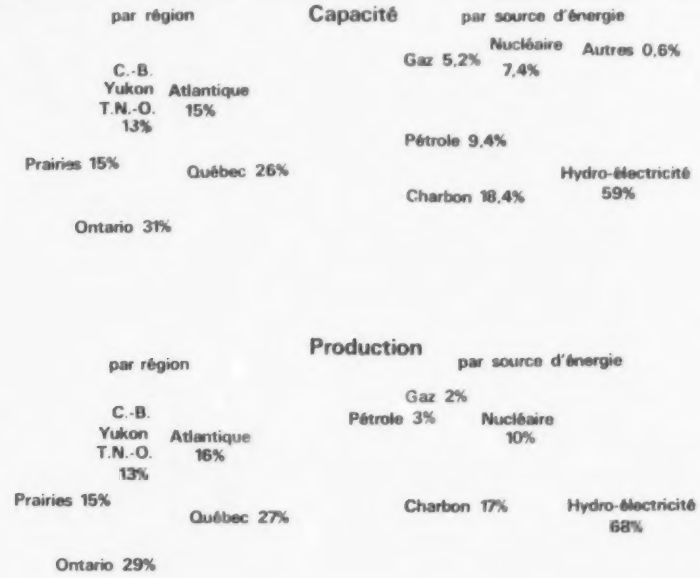


Tableau 4 Variations de la puissance installee realisees en 1982

Province	Nom du projet	Type de centrale	Nombre d unites	Puissance
				(MW)
Augmentations				
Nouvelle-Ecosse	Gisborne Canal	hydro-electrique	1	3 50
Nouveau-Brunswick	Pointe Lepreau	nucleaire	1	680 00
Quebec	Beauharnois	hydro-electrique	1	46 75
	La Grande - 3	hydro-electrique	3	576 00
	Lieux divers	combustion interne	7	4 08
	Trenche	hydro-electrique	1	50 00
Ontario	Thunder Bay	a vapeur (charbon)	1	149 00
	Bruce	turbine a gaz	2	28 00
	St Mary s	hydro-electrique (Great Lakes Power Co Ltd)	1	18 00
Territoires du Nord-Ouest	Lieux divers	combustion interne (Commission d energie du Nord canadien)	2	60
Total des augmentations				1 555 93
Retirees de service				
Quebec	Beauharnois	hydro-electrique	1	37 30
	Lieux divers	combustion interne	3	0 72
	Lieux divers	hydro-electrique	4	48 88
Total des installations retirees de service				86 90
Total des augmentations nettes				1 469 03

*Entreprises appartenant à la province, sauf indication contraire

Figure 2

Puissance installée et production d'énergie électrique selon le type principal de combustible, 1982

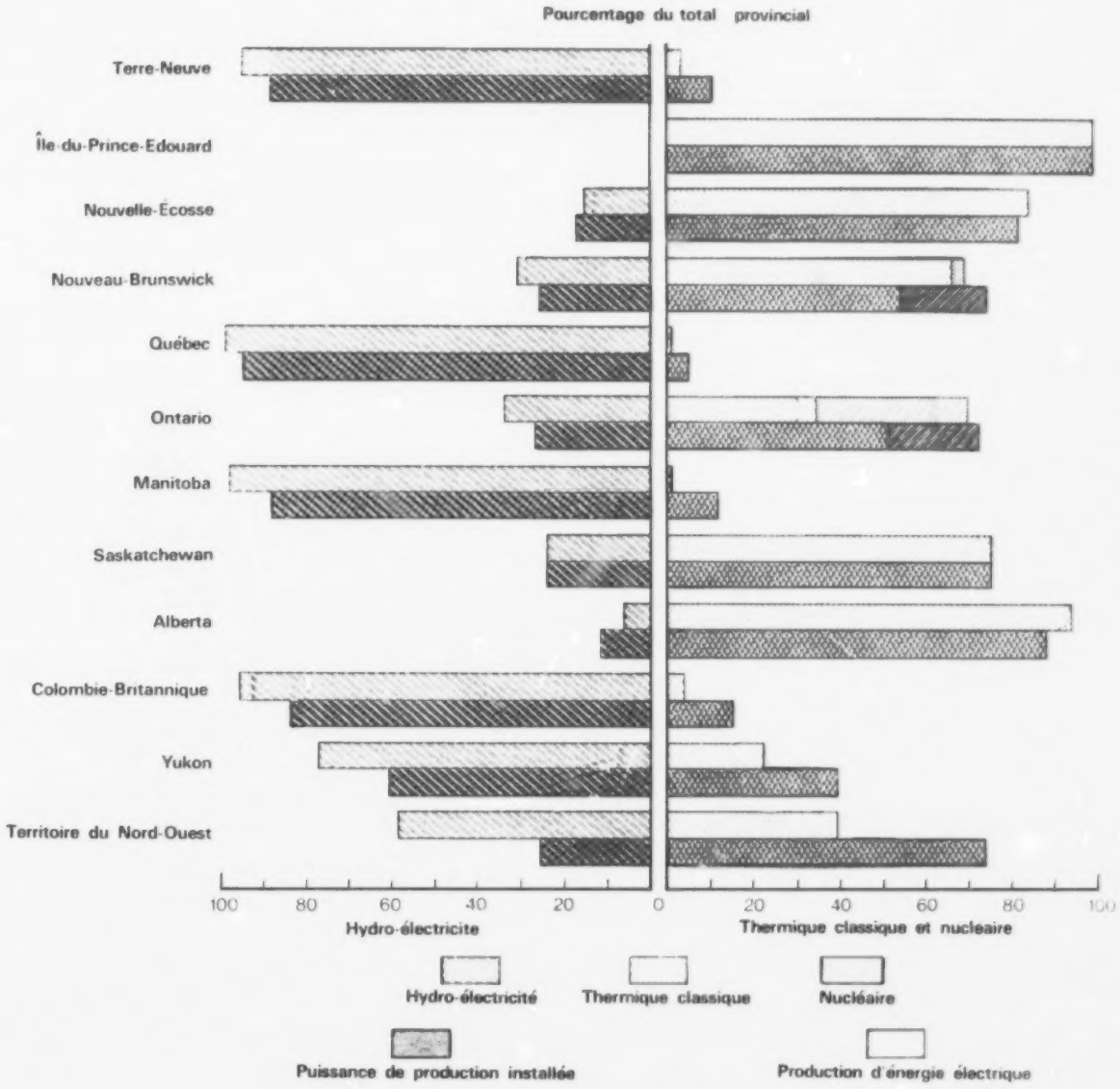
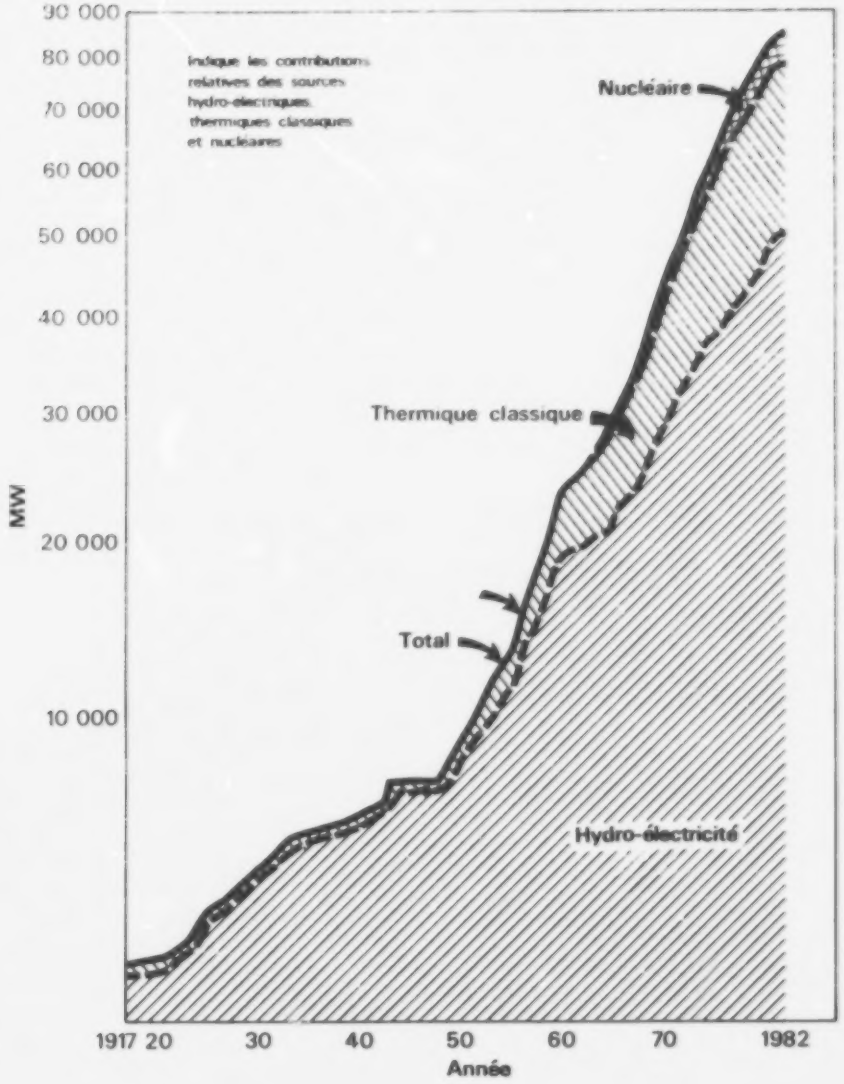


Figure 3

Progression de la puissance installée, 1917-1982



PROGRÈS ACCOMPLIS EN 1982

Cette rubrique se veut une vue d'ensemble des principaux évènements survenus dans le domaine de l'offre et de la demande d'électricité au Canada en 1982.

Faits saillants au niveau fédéral

En 1982, le gouvernement du Canada a fait état des progrès accomplis jusqu'à maintenant dans la poursuite des objectifs de son Programme énergétique national et il a défini les mesures à prendre pour relever certains défis dans la "Mise à jour du Programme énergétique national, 1982".

L'un des objectifs du Programme est de réduire la dépendance du Canada vis-à-vis du pétrole à 10 % de la consommation totale d'énergie dans les secteurs résidentiel, commercial et industriel d'ici à 1990. Pour y parvenir, l'électricité et le gaz naturel devront assurer une plus grande part des besoins d'énergie primaire; la part de l'électricité devrait atteindre 44 % en 1990, contre 33 % en 1975 et 39 % en 1982.

Le rôle de l'électricité dans le Programme canadien de remplacement du pétrole (P.C.R.P.)

Le Programme canadien de remplacement du pétrole, instauré en mai 1981, prévoit des subventions imposables pouvant atteindre 50 % du coût de la conversion au gaz naturel, à l'électricité ou à d'autres sources d'énergie renouvelable, et ce jusqu'à un maximum de 800 $ pour les installations de chauffage résidentielles. De mai 1981 à décembre 1982, on compte plus de 107 000 conversions du mazout à l'électricité, dans la plupart des cas au chauffage par plinthes. En guise de comparaison, mentionnons qu'il y a eu près de 124 000 conversions au gaz naturel, 87 000 au bois et 5 400 au propane.

Les Canadiens manifestent un intérêt croissant pour les nouvelles techniques telles que les thermopompes et les systèmes mixtes de chauffage à l'électricité et au mazout. Dans un système mixte, le bonnet d'un calorifère au mazout est muni d'éléments électriques qui fournissent la majeure partie de la chaleur requise. Le calorifère au mazout sert d'appoint durant les périodes les plus froides de l'hiver.

Même si l'électricité est appelée à jouer un rôle de plus en plus important dans la réalisation des objectifs de remplacement du pétrole, on ne prévoit pas de modifications profondes aux projets d'augmentation de capacité des services publics d'électricité, ni de fortes restrictions dans les exportations d'électricité vers les États-Unis.

Conversion de la centrale de Coleson Cove

Un programme en trois étapes a été lancé en janvier 1981 pour étudier le projet de conversion du mazout au charbon de la centrale de 1 000 MW de la Commission d'énergie électrique du Nouveau-Brunswick à Coleson Cove. L'étude est financée à même le Fonds de conversion des entreprises de service public prévu au Programme énergétique national. À ce jour, les deux premières étapes de l'étude sont terminées. L'établissement d'un échéancier pour la dernière étape a été retardé parce que la Commission d'énergie électrique et le ministère de l'Environnement du Nouveau-Brunswick n'ont pu s'entendre sur des normes acceptables de qualité de l'air. La Commission et le ministère fédéral de l'Énergie, des Mines et des Ressources (É.M.R.) s'efforcent actuellement de mettre au point un projet conjoint qui permettrait la reprise de l'étude.

Les résultats des deux premières étapes laissent entrevoir d'intéressantes perspectives économiques pour le projet de conversion. Cependant, il faudra revoir les hypothèses avancées au cours des différentes étapes de l'étude afin de tenir compte des incertitudes actuelles concernant le prix du pétrole et de la possibilité d'augmenter les importations d'électricité québécoise.

La baisse de croissance de la demande d'électricité et le rendement très prometteur du premier bloc de la centrale nucléaire de Pointe Lepreau doivent également être pris en considération. Si ces facteurs peuvent contribuer à une baisse dans la consommation de mazout à Coleson Cove, les avantages de la conversion au charbon se trouvent diminués.

Dans le cadre de l'étude, en plus d'examiner les sources possibles d'approvisionnement en charbon, on a envisagé l'utilisation provisoire du gaz naturel, advenant la possibilité de l'acheter à bon prix. Cependant, de par l'approvisionnement limité en gaz naturel et les échéances prévues pour sa disponibilité, son utilisation comme solution de rechange à la conversion au charbon est incertaine.

Par ailleurs, s'il fallait reporter la conversion de quelques années, on pourrait songer à l'utilisation d'un mélange de charbon et d'eau en guise de combustible. Ce genre de mélange fait actuellement l'objet de recherches menées par la Commission d'énergie électrique du Nouveau-Brunswick en collaboration avec l'É.M.R., dans le cadre du Programme d'utilisation du charbon.

L'industrie nucléaire

Le système nucléaire mis au point par l'Énergie atomique du Canada, Limitée (É.A.C.L.) en collaboration avec l'Hydro-Ontario s'est révélé l'un des meilleurs systèmes de production d'énergie nucléaire au monde. C'est le coefficient de capacité annuelle qui constitue l'indice de rendement dans ce domaine. Les huit réacteurs CANDU des centrales de Bruce et de Pickering se maintiennent au rang des meilleurs du monde.

Grâce à ces centrales nucléaires, l'Ontario dispose actuellement d'une puissance installée supérieure à 5 000 mégawatts, et les installations actuellement en construction permettront d'ajouter à cette production plus de 8 000 mégawatts. C'est en octobre qu'on a obtenu la criticité dans la première des quatre unités de Pickering B. A Pointe Lepreau, au Nouveau-Brunswick, et à Gentilly, au Québec, la criticité des nouvelles unités génératrices de 600 MW a été réalisée en 1982. Plus de la moitié de la production de Pointe Lepreau sera vendue à des services publics de la Nouvelle-Angleterre, et ce, pendant un certain nombre d'années. À la fin de 1982, plus de 30 % de la capacité de production de la centrale était déjà vouée à l'exportation.

En 1982, une unité génératrice de 600 MW construit à Wolsung, en Corée du Sud, est parvenue à la criticité après seulement 61 mois. Un quatrième réacteur CANDU de 600 MW devrait être inauguré en Argentine en 1983. Deux autres unités de 600 MW sont actuellement en construction en Roumanie mais le projet a été mis en veilleuse en 1982, à cause de la piètre performance de ce pays sur la scène financière internationale.

Malgré le succès du système CANDU en Ontario et ailleurs, on éprouve de la difficulté à obtenir de nouveaux contrats. La demande d'électricité a chuté en raison de la faiblesse de la croissance économique, au Canada comme à l'étranger. Même si les réacteurs CANDU actuellement exploités ou commandés continueront de recevoir tout l'appui requis, de nouveaux contrats sont nécessaires pour permettre à l'industrie nucléaire de continuer de fonctionner et pour assurer la construction de nouveaux réacteurs à un prix concurrentiel.

À la suite d'un effort concerté de l'industrie, du gouvernement et des services publics d'électricité, sous la conduite de l'E.A.C.L. qui est le principal organisme de la commercialisation des réacteurs CANDU, le Canada a présenté une offre au Mexique pour la vente de 4 réacteurs CANDU de 600 MW.

Cependant, le Mexique a décidé de reporter la réalisation de son ambitieux programme nucléaire. Le Canada a néanmoins continué de chercher des débouchés pour ses réacteurs en Corée du Sud, en Yougoslavie, en Égypte et ailleurs.

Révision de l'industrie nucléaire

A la demande du Premier ministre, le ministère de l'Énergie, des Mines et des Ressources a entrepris en 1980 une révision de l'industrie nucléaire canadienne. En août 1981, le ministre de l'Énergie, des Mines et des Ressources présentait une série de précis sur tous les aspects de cette industrie. Le document "Révision de l'industrie nucléaire" a été publié en août 1982.

Cet examen met l'accent sur la situation économique actuelle et prévue de l'industrie nucléaire canadienne, une industrie frappée par la récession internationale qui a ralenti la croissance de la demande. La plupart des provinces canadiennes disposent d'une capacité excédentaire de production; pour la prochaine décennie on ne prévoit donc aucune expansion du nucléaire au-delà de ce qui avait déjà été planifié. Sur la scène internationale, les ventes de réacteurs font l'objet d'une plus forte concurrence, étant donné la détermination des constructeurs à protéger leur industrie sur un marché resserré.

On prévoit pour les années 90 une demande accrue de capacité. Le système nucléaire canadien, fondé sur la technologie canadienne et sur l'existence au Canada d'immenses gisements uranifères, devrait normalement constituer un instrument privilégié pour une expansion éventuelle de la capacité de production. Le gouvernement du Canada reconnaît au système CANDU de nombreux atouts en tant qu'option énergétique. Dans la "Révision de l'industrie nucléaire", le gouvernement étudie un certain nombre de plans d'action qui permettraient de préserver l'option CANDU.

Dans la "Mise à jour du P.É.N." de mai 1982, le gouvernement du Canada a indiqué qu'il appuyait l'industrie nucléaire. Plus spécifiquement, il étudiera la possibilité de contribuer à la construction de futures centrales, y compris celles initialement conçues pour le marché à l'exportation.

On envisage la construction d'un deuxième réacteur CANDU à Pointe Lepreau mais le projet ne sera mis à exécution que si le marché peut absorber la production dans sa totalité. Il pourrait être utile, à cet égard, que le gouvernement fédéral fournisse des garanties financières.

Faits saillants et questions au niveau provincial

Le Programme de chauffage mixte au Québec

Devant la baisse de croissance de la demande, Hydro-Québec a annoncé en 1982 qu'elle reportait de six ans la construction de nouvelles centrales. De 1982 à 1985, la société entend réduire ses dépenses et promouvoir de façon plus dynamique les ventes d'électricité à l'intérieur et à l'extérieur de la province.

Afin de promouvoir les ventes d'électricité dans la province, Hydro-Québec a lancé un programme de subventions pour l'installation de systèmes de chauffage mixte dans les maisons unifamiliales. Le système de chauffage mixte utilise l'électricité comme source d'énergie principale, et un autre type d'énergie, normalement le mazout, comme source d'appoint.

Dans un système mixte, les deux systèmes de chauffage sont commandés par un capteur de température installé à l'extérieur de la maison. Au-dessus d'une certaine température - prédéterminée -, le chauffage se fait à l'électricité. En-deçà de cette température, le capteur met en marche le système d'appoint. Ainsi, au moyen d'un système très simple, on rentabilise l'utilisation du mazout en recourant à ce combustible seulement pendant les périodes de grand froid; le reste du temps, l'énergie électrique suffit à combler les besoins.

Hydro-Québec offre une subvention de 650 $ aux propriétaires qui convertissent leur système actuel au chauffage mixte. La subvention sera accordée au 100 000 premiers candidats admissibles jusqu'à la fin de l'année 1983. Cette subvention est accordée pour la conversion de systèmes au mazout en systèmes de chaffage mixte à l'électricité et à une seconde source d'énergie autre que le gaz naturel. La subvention sera ramenée à 500 $ en 1984. En 1983, le programme incluera possiblement les propriétaires et les locataires d'habitations à logements multiples. Les consommateurs qui convertissent leur système de chauffage au mazout en un système de chauffage d'un autre type seront également admissibles à la subvention maximale de 800 $ accordée par le gouvernement fédéral dans le cadre de son Programme canadien de remplacement du pétrole.

Un autre programme destiné au secteur industriel prévoit des subventions pour la conversion à l'électricité des chaudières au mazout. Des programmes semblables ont été créés pour les habitations à plusieurs logements et les installations commerciales.

Rapport de la Commission royale d'enquête sur le coût de l'électricité vendue aux résidents de l'Île-du-Prince-Édouard

En juillet 1981, la *Maritime Electric Company Ltd.* a demandé à la *Public Utilities Commission* de l'Île-du-Prince-Edouard l'autorisation d'augmenter ses tarifs de base de 21,4 %. En octobre 1981, cette Commission autorisait une augmentation de 18 % des tarifs. En novembre, une seconde et dernière ordonnance autorisait une nouvelle hausse de 3 %.

Devant la vive protestation des citoyens face à ces fortes majorations et leur crainte de nouvelles hausses, le gouvernement a chargé une Commission royale de faire enquête sur le coût de l'énergie électrique, en décembre 1981.

Cette Commission, présidée par Melvin McQuaid, C.R., s'est penchée sur les problèmes suivants: le coût élevé des approvisionnements énergétiques et les restrictions financières. Elle a étudié les choix offerts au gouvernement de la province et à la société d'électricité.

Le rapport faisant état des conclusions de l'enquête a été publié en septembre 1982. On y trouve un certain nombre de critiques à l'égard de la *Maritime Electric Company Ltd.*, une société privée. Toutefois, ces critiques ne permettent pas d'affirmer que la *Maritime Electric* a agi de façon inopportune et le Commissaire conclut que la société est "organisée de façon à fonctionner efficacement et qu'elle est gérée avec efficacité".

Vue du nouveau centre de contrôle des lignes de transport d'énergie de l'Hydro-Québec, inauguré en octobre 1982 à Montréal.

Hormis les propositions de recourir aux subventions du gouvernement fédéral et de négocier de nouveaux contrats d'achat d'électricité avec des services publics voisins, le rapport fait peu de suggestions précises pour réduire le coût de l'énergie. Des études ont été entreprises par des experts-conseils afin d'envisager d'autres solutions pour l'Île-du-Prince-Édouard.

Le différend entre Québec et Terre-Neuve au sujet de Churchill Falls

Le contrat signé en 1969 donne à l'Hydro-Québec le droit d'acheter, jusqu'en 2041, environ 90 % de la production de Churchill Falls, une centrale hydro-électrique de 5 225 MW au Labrador (Terre-Neuve). Le prix de vente est fixé entre 2 $ et 3 $ le mégawattheure, soit moins du dixième du coût actuel de toute augmentation à la capacité de production.

Il est à remarquer que l'Hydro-Québec aurait pu construire ses propres centrales hydro-électriques au Québec, au lieu d'acheter de l'électricité de Churchill Falls. Cela lui aurait permis d'approvisionner la province à un coût comparable et lui aurait procuré la même immunisation contre l'inflation.

Le litige au sujet de Churchill Falls porte sur deux points fondamentaux. D'abord, Terre-Neuve réclame l'accès aux ressources de Churchill Falls, au même prix que le Québec. Deuxièmement, Terre-Neuve veut que le Québec paie cette énergie plus cher, en raison de la forte hausse des prix survenue dans le secteur de l'énergie de rechange depuis l'inauguration de la centrale au début des années 70.

En 1976, Terre-Neuve a engagé un procès afin d'obtenir, en plus des 300 MW auxquels lui donne droit le contrat de vente d'électricité, 800 autres mégawatts de cette centrale de 5 225 MW.

En 1985, l'aménagement des grands sites hydro-électriques sur l'île de Terre-Neuve sera achevé. Toute capacité additionnelle devra provenir de centrales alimentées aux combustibles fossiles, implantées dans l'île, ou de nouvelles installations hydro-électriques au Labrador.

N'ayant pas encore réussi à obtenir plus d'énergie de Churchill Falls par la voie des tribunaux, le Parlement de Terre-Neuve a adopté en 1980 une loi qui, si elle était proclamée, révoquerait le permis d'utilisation des eaux de Churchill Falls, ce qui équivaudrait à l'expropriation de la centrale.

Trois questions distinctes sont présentement débattues devant les tribunaux:
(a) Demande devant les tribunaux de Terre-Neuve afin de faire reconnaître le droit du gouvernement d'exiger 800 MW en sus de ce qui lui est accordé en vertu du contrat actuel. Le principe soutenu par Terre-Neuve pourrait, s'il était reconnu, s'étendre progressivement à toute la production de la centrale de Churchill Falls et, éventuellement, compromettre tous les droits consentis par contrat à l'Hydro-Québec. En juin 1983, la Cour suprême de Terre-Neuve a décrété que la province n'avait pas droit aux 800 MW additionnels et qu'elle pouvait seulement recevoir de l'énergie excédentaire une fois remplies les obligations contractuelles de la compagnie Churchill Falls. Terre-Neuve fera appel de ce jugement.

(b) Demande devant les tribunaux du Québec afin d'obtenir la confirmation que si la revendication de Terre-Neuve était reconnue, elle constituerait une violation de contrat de la part de la compagnie Churchill Falls, entraînant l'invalidation dudit contrat. Hydro-Québec pourrait alors poursuivre Terre-Neuve pour dommages et intérêts. La Cour suprême du Canada a récemment déclaré que l'Hydro-Québec pouvait demander aux tribunaux du Québec leur interprétation des modalités du contrat mais que la société ne pouvait pas faire comparaître le gouvernement de Terre-Neuve devant les tribunaux québécois. Les audiences devant la Cour supérieure du Québec ont débuté le 21 mars 1983.

(c) Demande devant la Cour suprême du Canada afin d'établir la validité de la "Water Rights Reversion Act", en vertu de laquelle le Parlement de Terre-Neuve se propose d'annuler le permis d'utilisation des eaux sur lequel repose le contrat de Churchill Falls.

Le 5 mars 1982, la Cour suprême d'appel de Terre-Neuve a reconnu la constitutionnalité de la nouvelle Loi, et le fait qu'elle relève bien de la compétence de la législature provinciale. Hydro-Québec en a appelé de ce jugement devant la Cour suprême du Canada.

Le 17 septembre 1982, le gouvernement fédéral a déposé devant la Cour suprême du Canada un exposé des faits dans lequel il précise que la Loi vise une entreprise extra-provinciale et que, par conséquent, elle sert à "abolir des droits et des responsabilités étrangers à la province de Terre-Neuve". La Cour suprême a entendu les débats en octobre 1982 et devrait rendre sa décision en 1983.

Le gouvernement fédéral incite les deux provinces à s'entendre par voie de négociations.

LE COMMERCE CANADO-AMÉRICAIN DE L'ÉLECTRICITÉ

Le commerce de l'électricité entre le Canada et les États-Unis remonte au début du vingtième siècle. Depuis ce temps et jusqu'à récemment, les exportations nettes (c'est-à-dire les exportations moins les importations) ont été peu importantes, tant pour l'un pays que pour l'autre. Cependant, à compter des années 70, le volume des exportations nettes du Canada vers les États-Unis a augmenté et les revenus tirés de cette source constituent un élément important dans la balance des paiements du Canada (Tableau 5).

En 1982, les exportations nettes d'électricité ont produit un revenu de 1,1 milliard de dollars, ce qui représente 18 % du solde de notre commerce d'approvisionnements énergétiques sur les marchés internationaux et 11 % du solde de notre commerce de marchandises avec les États-Unis.

L'une des principales raisons de l'augmentation de nos exportations nettes d'électricité vers les États-Unis tient au fait que les deux pays ne produisent pas de l'électricité à partir des mêmes sources. La puissance excédentaire canadienne, provenant à 60 % d'installations hydro-électriques, est utilisée aux États-Unis pour remplacer la production coûteuse des centrales au mazout et autres centrales à combustibles fossiles.

Ce sont surtout les États du nord-est des États-Unis qui utilisent cette électricité de remplacement. Ainsi, l'électricité exportée vers l'État de New York est produite dans des centrales hydro-électriques du Québec et dans des centrales au charbon de l'Ontario, tandis que l'électricité des centrales nucléaires et des centrales au mazout du Nouveau-Brunswick est exportée vers la Nouvelle-Angleterre. L'énergie hydro-électrique du Manitoba sert à remplacer la production des centrales au charbon des États du centre-ouest, tandis que les États de la côte ouest importent de l'énergie hydro-électrique de la Colombie-Britannique pour réduire la production de leurs centrales au gaz et au mazout.

Tableau 5. Importations et exportations annuelles d'énergie électrique

Année	Production nette du Canada	Exportations d'électricité canadienne		Importations d'électricité américaine		Volume net des exportations	Valeur nette des exportations
	(GWh)	(GWh)	% de (1)	(GWh)	% de (1)	(GWh)	(en milliers de dollars)
	(1)						
1959	104 671	4 593	4 4	512	0 5	4 081	13 008
1960	114 378	5 494	4 8	357	0 3	5 137	13 888
1961	113 713	4 180	3 7	1 394	1 2	2 786	12 592
1962	117 469	4 034	3 4	2 779	2 4	1 255	13 891
1963	122 238	3 624	3 0	2 884	2 4	740	4 433
1964	134 987	4 185	3 1	3 121	2 3	1 064	5 658
1965	144 274	3 570	2 5	3 575	2 5	-5	-1 836
1966	158 135	4 310	2 7	3 057	1 9	1 253	5 970
1967	165 625	4 066	2 4	4 142	2 5	-76	-6 196
1968	176 378	3 646	2 1	4 129	2 3	-483	-2 725
1969	191 102	4 688	2 5	3 333	1 7	1 355	10 198
1970	204 723	5 631	2 8	3 245	1 6	2 386	22 445
1971	216 472	6 985	3 2	3 378	1 6	3 607	38 208
1972	240 213	10 379	4 3	2 381	1 0	7 998	61 590
1973	263 335	16 879	6 4	2 249	0 8	14 630	108 633
1974	280 256	15 399	5 5	2 441	0 9	12 958	168 320
1975	273 392	11 375	4 2	4 174	1 5	7 201	102 019
1976	294 043	12 804	4 4	3 590	1 2	9 214	167 200
1977	317 196	19 957	6 3	2 690	0 8	17 267	406 138
1978	335 641	21 602	6 4	2 092	0 6	19 510	476 791
1979	352 304	31 378	8 9	1 792	0 5	29 586	737 802
1980	367 306	30 176	8 2	2 939	0 8	27 237	790 640
1981	378 531	35 372	9 3	1 497	0 4	33 876	1 138 250
1982	375 449	34 214	9 1	2 848	0 8	31 370	1 100 489

Source: Office national de l'énergie

1. Premiers échanges commerciaux d'électricité

Les contrats régissant actuellement la vente et les échanges d'énergie électrique entre le Canada et les États-Unis sont le fruit d'une expérience acquise pendant plus de 80 ans de négoce.

Dans les premiers stades du développement de l'industrie de l'électricité au Canada, ce sont des entreprises du secteur privé qui ont entrepris la construction de centrales hydro-électriques, thermiques et au mazout. La rivière Niagara, manifestement un site de prédilection, a tôt été aménagée. La proximité de la frontière canado-américaine a encouragé les entrepreneurs à chercher à vendre du côté américain.

À l'époque, il était impossible d'écouler cette production au Canada, faute de marchés. Par conséquent, presque toute l'électricité produite dans la région du Niagara était exportée en vertu de contrats à long terme vers les États-Unis, au moyen de câbles aériens franchissant la Niagara et de lignes de transport suspendues sous le pont Rainbow à Niagara Falls, New York. La première ligne de transport à franchir la frontière était un circuit de 12 kV conçu à Niagara Falls en 1901.

Les premières ententes en matière d'exportation ont été négociées par des sociétés affiliées, de part et d'autre de la frontière. Cependant, les sociétés non-affiliées reluquaient également le marché américain. En 1904, l'Ontario Power garantissait à un service public de Buffalo la livraison de 46 000 kW sur une période de 46 ans.

L'Ontario n'était pas la seule province à exporter de l'électricité au début des années 1900. Les origines du commerce international entre le Québec et le Vermont remontent à 1914, tandis que le Nouveau-Brunswick et le Maine entretiennent depuis longtemps des relations de collaboration en matière de production et de mise en marche.

Au Canada, l'augmentation de la production et l'aménagement des réseaux de transport ont toujours précédé la demande intérieure. Les différences au niveau de la géographie, de la démographie, de la disponibilité des ressources et de la fluctuation saisonnière de la demande sont les principales raisons pour lesquelles le commerce de l'électricité entre le Canada et les États-Unis s'est tôt développé.

Les ventes effectuées en vertu de contrats à long terme avec les services publics américains généraient les fonds nécessaires au développement de l'industrie hydro-électrique au Canada. On a craint cependant que cette façon de procéder ne retarde éventuellement le développement économique et qu'elle ne prive les Canadiens de leurs ressources énergétiques.

2. Évolution de la politique d'exportation du Canada

Sur les instances du public, pour qui les ressources énergétiques canadiennes devaient être réservées aux Canadiens, les gouvernements fédéral et provinciaux ont légiféré. Déjà, en 1903, quelques municipalités de l'Ontario possédaient leur propre réseau de distribution d'électricité et envisageaient la possibilité de construire des réseaux de transport. Ceux-ci permettraient d'acheminer la production de Niagara Falls vers les centres de distribution locaux. Le gouvernement provincial a alors reconnu la nécessité d'un organisme central qui fournirait un appui administratif à ces municipalités. En établissant des réseaux d'approvisionnement pour les marchés provinciaux, cet organisme servirait à préserver les ressources canadiennes.

C'est ainsi qu'est née, en 1903, la Commission hydro-électrique de l'Ontario, par l'adoption de la *Ross Act* qui autorisait ce service à passer des contrats de livraison de grandes quantités d'énergie et l'autorisait en outre à construire, à posséder et à exploiter un réseau provincial interconnecté de transport d'énergie.

Au début, les services privés s'opposèrent à l'existence de la Commission sous prétexte que la nouvelle réglementation brimait leurs droits d'exportation. En 1910, néanmoins, on achevait la construction de la première ligne de transport d'électricité reliant Niagara Falls à sept municipalités de l'Ontario.

Tous ces efforts de préservation des ressources hydro-électriques recevaient l'appui du fédéral. En 1907, le gouvernement adoptait la *Electricity and Fluid Exportation Act* dans le but de réglementer les exportations d'électricité et de gaz naturel.

Ce programme législatif modifia radicalement le marché à l'exportation, par l'introduction d'un certain nombre de conditions auxquelles les services publics devaient répondre à la satisfaction du Gouverneur en conseil.

En vertu de la Loi, il fallait maintenant obtenir, pour chaque contrat d'exportation, un permis faisant état de la quantité maximale d'énergie autorisée. Ces permis devaient être renouvelés à chaque année. De plus, les permis n'autorisaient que l'exportation d'énergie excédentaire. Le prix d'exportation exigé par le détenteur de permis devait être égal ou supérieur au prix imposé aux consommateurs canadiens dans des "conditions de vente analogues".

La Loi prévoyait également la mise sur pied d'un mécanisme de déclaration permettant de superviser les exportations. Le détenteur de permis devait donc remettre au ministre de l'Industrie et du Commerce des rapports mensuels sur sa production, ses ventes au pays et à l'étranger.

Des droits annuels d'exportation n'excédant pas 10 $ par année HP furent autorisés sur les ventes à l'étranger. En vertu du décret du conseil C.P. 397 (16 mars 1925), le droit annuel fut fixé à 2 $ par année HP. Les exportations furent assujetties à ce droit jusqu'en 1963.

Le but de ce droit était d'intéresser les producteurs du Niagara au marché canadien. C'était une façon de les prévenir que le gouvernement pouvait rendre le marché à l'exportation peu rentable. De même, les permis d'une année rappelaient aux exportateurs qu'ils ne devaient pas prendre pour acquis leur droit d'exporter de l'énergie. Les services publics américains ne devaient donc pas se fier sur la production canadienne d'électricité pour répondre à leur demande de base.

La Electricity and Fluid Exportation Act n'a pas été modifiée avant 1957. Le gouvernement du Canada a alors réalisé qu'il fallait répondre aux besoins des industries régionales avant d'autoriser des permis d'exportation. Aussi, plusieurs étaient d'avis que les responsabilités juridictionnelles du Canada devaient être confiées à un organisme nouveau, ne relevant pas du ministère de l'Industrie et du Commerce.

En 1958 et en 1959, la Commission Borden sur l'énergie recommandait la création d'un Office national de l'énergie (O.N.E.) et l'adoption d'une loi de remplacement de la *Electricity and Fluid Exportation Act* de 1907. En 1959, le Parlement a décrété la Loi sur l'Office national de l'énergie et abrogé l'*Exportation Act* de 1907.

C'est en 1963 que l'honorable Mitchell Sharp, alors ministre de l'Industrie et du Commerce, a présenté la première déclaration officielle d'une "Politique nationale de l'énergie". Cette déclaration prenait le contre-pied de la politique restrictive adoptée par le gouvernement depuis 1907, tout en poursuivant des objectifs de protection des ressources canadiennes.

La nouvelle politique favorisait la mise en valeur d'abondantes ressources énergétiques à un coût peu élevé, de même que l'interconnexion des différents réseaux à l'intérieur du Canada. Elle encourageait les exportations et l'établissement d'interconnexions entre le Canada et les États-Unis.

C'est à ce moment que fut introduit le concept de l'aménagement anticipé des ressources hydrauliques dans les régions éloignées du Canada, à des fins initiales d'exportation. Cependant, tout contrat d'exportation devait prévoir des clauses d'approvisionnement à bon prix des marchés canadiens, advenant la demande. La nouvelle politique envisageait les exportations d'un oeil favorable dans les cas suivants:

- L'établissement d'un réseau de secours pour les urgences, permettant ainsi de réduire la capacité de production de réserve exigée des services publics d'électricité.
- Les interversions économiques entre les centrales.
- Les ventes d'énergie interruptible excédentaire.
- Les échanges de puissance complémentaire. Puisque la consommation de pointe s'effectue en hiver au Canada et en été aux États-Unis, la puissance et l'énergie fournies par le Canada en été peuvent être remises par les États-Unis en hiver.
- La vente de quantités de puissance garantie pour des périodes restreintes, afin de permettre la "construction étape par étape des installations de production les plus économiques possibles de part et d'autre de la frontière". [1]

La politique appuyait également les exportations d'électricité vers les régions frontalières des États-Unis qui, pour des raisons géographiques, pouvaient être desservies de façon plus économique par le Canada. Cette pratique a cours depuis les premiers échanges d'électricité.

Vers la fin de 1977, les États-Unis proposèrent la réalisation d'un projet d'étude conjoint sur la collaboration canado-américaine en matière d'échanges de grandes quantités d'électricité. En 1979, les auteurs du rapport intitulé "Échanges d'électricité entre le Canada et les États-Unis" conclurent qu'il était possible d'accroître de façon significative les échanges internationaux dans toutes les régions frontalières. Ces échanges seraient mutuellement profitables, en permettant notamment de réduire la consommation de pétrole et d'améliorer la fiabilité des réseaux. Entre autres, les recommandations suivantes figuraient au rapport:

- l'amélioration de la communication et une concertation accrue entre les organismes de réglementation, et entre ces organismes et les entreprises de service public;
- une affirmation claire et nette des politiques et des lignes directrices du gouvernement concernant le processus de réglementation des échanges internationaux;
- l'adoption d'une politique d'établissement des prix d'exportation, afin de maximiser les possibilités et les bénéfices;
- la mise sur pied de programmes d'information publique afin d'expliquer les avantages procurés par les échanges internationaux d'électricité.

En 1982, le gouvernement du Canada a appuyé l'expansion du marché à l'exportation de l'électricité dans la "Mise à jour du Programme énergétique national" (P.É.N.). Le Programme est favorable à l'augmentation anticipée de la capacité de production, moyennant "une répartition équitable des risques et des charges pécuniaires entre acheteurs et vendeurs ainsi que le respect des normes appropriées de protection de l'environnement"[2].

Un programme d'expansion de ce genre pourrait être financé à même les revenus générés par les exportations et il est fidèle à l'énoncé de politique de 1963. Dans la mise à jour du P.É.N. de 1982, le gouvernement a indiqué qu'il était disposé à envisager un appui pour la construction de centrales nucléaires initialement conçues pour alimenter le marché à l'exportation.

Le gouvernement du Canada contribuerait financièrement à la réalisation d'une entente avec les services publics des États-Unis visant, dans un avenir immédiat, la construction de la centrale Lepreau II. Le projet devrait cependant répondre aux critères généraux établis par le gouvernement en matière de partage des coûts et des risques.

La position du gouvernement du Canada quant aux exportations d'électricité a été précisée davantage en 1982. Devant des auditoires des États-Unis, le ministre de l'Énergie, des Mines et des Ressources et le ministre d'État aux Mines ont réitéré l'appui du Canada en ce qui concerne le maintien du commerce de l'électricité et l'accroissement des exportations. Les ministres responsables ont également souligné la fiabilité des exportations canadiennes d'électricité et le désir du Canada de promouvoir le commerce entre les deux pays.

3. Milieu institutionnel

Les structures institutionnelles du Canada et des États-Unis ont influé sur l'évolution des échanges d'électricité. Il existe entre les deux pays des différences considérables au niveau de la possession des services publics, de la conduite des opérations, de la réglementation. Il y a collaboration néanmoins grâce au North American Electric Reliability Council (NERC), organisme chargé de coordonner la planification et la fiabilité du design des réseaux nord-américains. Les services publics du Canada ayant des interconnexions avec les réseaux américains sont membres du NERC.

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[1] Exposé de la "Politique nationale de l'énergie" par l'honorable Mitchell Sharp, ministre de l'Industrie et du Commerce, le 8 octobre 1963.

[2] *Mise à jour du Programme énergétique national*, 1982, Énergie, Mines et Ressources, 1982.

3.1 Compétence gouvernementale - Canada

Les articles 91 et 92 de la Constitution canadienne répartissent la compétence en matière d'électricité entre les autorités fédérales et provinciales du Canada.

La compétence provinciale s'étend aux richesses naturelles sises dans les limites de son territoire. L'administration de la production et de la distribution de l'électricité dans une province quelconque relève donc du gouvernement provincial.

L'article 91 de la Constitution confirme la compétence du gouvernement fédéral dans le domaine du commerce international et interprovincial. Énoncée pour la première fois dans l'*Electricity and Fluid Exportation Act* de 1907, cette compétence a été réitérée par la Loi sur l'Office national de l'énergie (1959).

La compétence du gouvernement fédéral en matière d'électricité a été limitée à la réglementation des lignes internationales de transport et à l'octroi de permis d'exportation. Dans l'exercice de son mandat, l'Office national de l'énergie voit à ce que chaque demande d'exportation réponde aux conditions suivantes:

- les exportations doivent être excédentaires aux besoins canadiens prévus;
- les prix imposés par les détenteurs de permis doivent être justes et raisonnables ("dans l'intérêt public");
- la période maximale de validité des permis est de 25 ans (la plupart des permis sont délivrés pour des périodes qui varient entre 5 et 10 ans, selon les requêtes).

Dans l'application de la première condition, les services publics voisins jouissent d'un premier droit de refus de tout projet d'exportation présenté en vertu des mêmes modalités.

L'Office peut décider que, par exemple, les répercussions économiques et environnementales, la possibilité de création d'emplois et la balance des paiements affectent "l'intérêt public".

L'Office national de l'énergie dispose de certaines méthodes afin de déterminer si le prix exigé pour les exportations répond aux conditions fixées en matière de protection de "l'intérêt public". D'abord, le prix de vente de l'énergie ne doit pas être inférieur à son coût de production. Ensuite, il ne doit pas être inférieur au coût défrayé par les Canadiens pour les mêmes biens. Enfin, il ne doit pas être inférieur à celui de la source d'énergie la moins coûteuse offerte à l'acheteur des États-Unis.

L'interprétation de ces critères est souple. On considère que l'importateur a droit à certains encouragements, étant donné les différences de prix entre les approvisionnements locaux et importés. La politique de fixation des tarifs tient également compte du fait que certains clients américains investissent dans des installations canadiennes de production et de transport d'électricité en vue d'importer une partie de cette production.

Les pouvoirs de l'Office national de l'énergie ont été étendus en février 1983. Ainsi, le Gouverneur en conseil peut assujettir toute installation construite et exploitée à des fins de transfert interprovincial d'électricité aux dispositions de la Loi de l'O.N.E. relatives aux lignes internationales de transport. Par ailleurs, l'Office peut autoriser l'expropriation des terres pour la construction de lignes de transport internationales et autres. Ces pouvoirs sont analogues à ceux qu'il détient en matière de construction des pipe-lines.

Les provinces jouissent de la compétence première en matière d'environnement. Cependant, les deux paliers de gouvernement peuvent recourir à l'O.N.E. pour une analyse des questions environnementales au stade de la mise en pratique d'un projet. Lorsqu'un projet implique la participation, les fonds ou la propriété du gouvernement fédéral, le Bureau fédéral d'évaluation et de révision environnementales intervient à l'étape de la planification du projet. Cette intervention peut se traduire par une enquête publique. Il est à remarquer toutefois que peu de projets d'exportation, s'il en est, bénéficieront de l'aide financière du gouvernement fédéral; ils n'affecteront guère, non plus, des terres appartenant au fédéral.

Le gouvernement fédéral exige que toute demande de permis de construction pour des lignes de transport destinées à franchir des cours d'eau navigables respecte la Loi sur les eaux navigables. Une autorisation distincte doit également être obtenue du ministère des Transports et la demande doit respecter la Loi sur les pêcheries.

À l'exception du partage des responsabilités en matière d'environnement, ce qui, jusqu'à maintenant, n'a pas posé de problèmes, la compétence des gouvernements fédéral et provinciaux est clairement définie. L'Office national de l'énergie recommande aux services publics exportateurs d'énergie de consulter avec lui avant de soumettre une demande; une connaissance préalable des procédures et des politiques de réglementation permet de réduire la durée de traitement de la demande.

3.1.1 L'octroi des permis au Canada

Le requérant d'un permis d'exportation doit fournir à l'O.N.E. tous les renseignements énoncés à la partie VI de la Loi sur L'Office national de l'énergie.

Lorsqu'il étudie les demandes, l'Office établit une distinction entre les projets d'exportation de puissance garantie et les projets d'exportation d'énergie interruptible. Dans le cas des exportations de quantités de puissance garantie, l'Office doit effectuer une étude plus détaillée étant donné que la puissance garantie doit "être disponible en tout temps au cours de la période visée par l'entente"[3].

[3] Partie VI, Loi sur l'Office national de l'énergie, 1978.

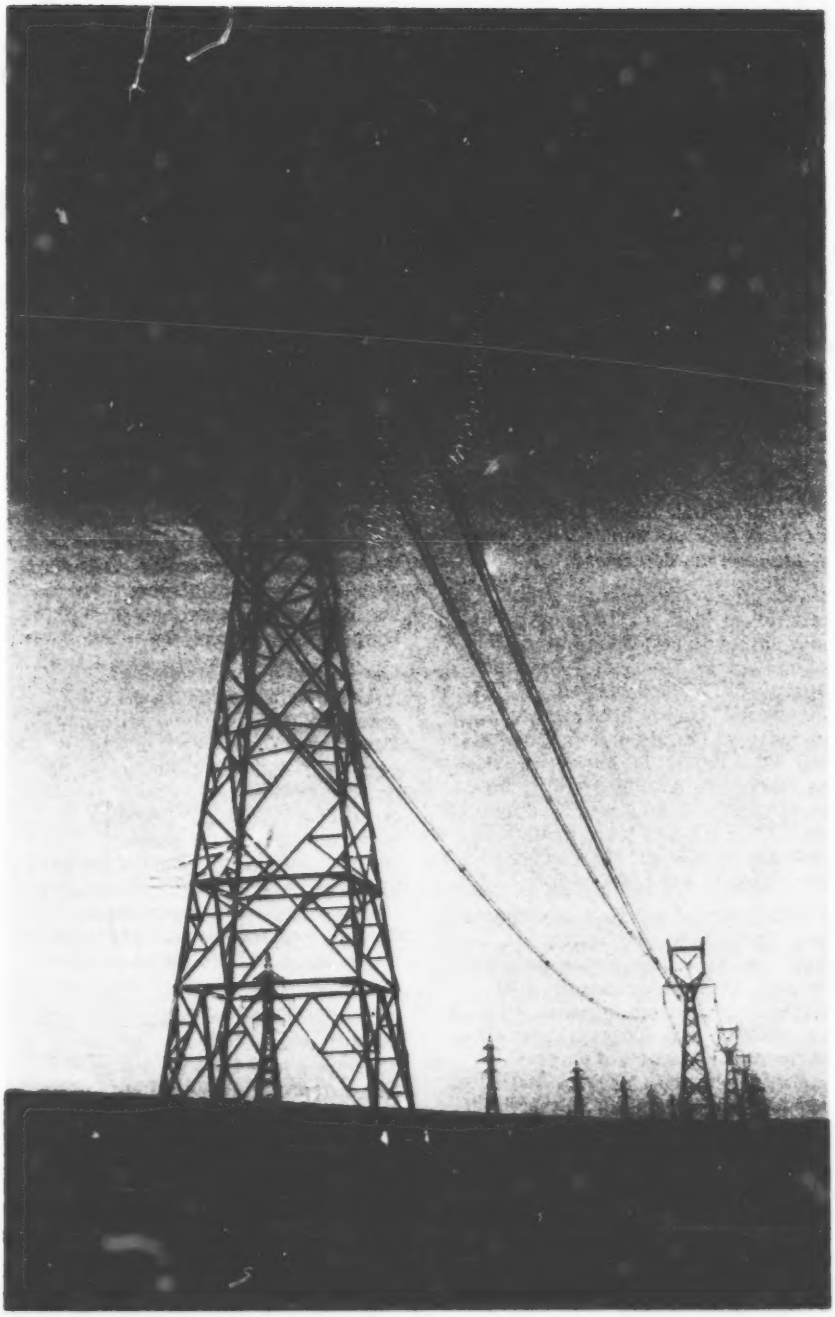
Les demandes déposées devant l'Office font habituellement l'objet d'une audience publique au cours de laquelle sont présentés des plaidoyers en faveur ou à l'encontre de la demande. L'audience est tenue devant un comité composé de trois membres de l'Office; la décision du comité est rendue sous forme d'un document intitulé "Motifs de la décision", préparé après étude des témoignages présentés. Ce document fait état de la décision et des raisons qui l'ont motivée. Il contient une description de la demande, un résumé de tous les témoignages et une définition des conditions applicables au certificat de service public ou au permis d'exportation.

L'Office a formulé certaines exigences de base en ce qui concerne les demandes de certificat d'exploitation de lignes internationales de transport:

- disponibilité de l'énergie que doit transporter la ligne;
- identification des marchés;
- faisabilité économique de la ligne;
- considérations financières;
- intérêt public;
- répercussions environnementales.

Lorsque l'intervention du Bureau fédéral d'évaluation et de révision environnementales s'avère nécessaire, les projets proposés doivent alors être étudiés minutieusement, dès l'étape de la planification, afin de déterminer l'ampleur des répercussions environnementales. Si le ministre du ministère responsable estime qu'un projet entraîne de sérieuses répercussions environnementales, il faut soumettre le cas au ministre de l'Environnement, qui demande alors la tenue d'une enquête publique sous la direction d'un Comité indépendant d'évaluation environnementale. L'enquête du Comité est habituellement réalisée dès l'étape de la planification du projet et terminée avant que des décisions fermes ne soient prises.

Les projets sont aussi évalués d'après un compte rendu des répercussions environnementales et en fonction des témoignages présentés au cours d'une audience. Un rapport détaillé,



La ligne de transport d'énergie de 500 kV de Winnipeg à Minneapolis, la troisième interconnexion du Manitoba avec l'American Power Grid.

accompagné de recommandations, est présenté au ministre de l'Environnement. Les décisions sont prises en consultation avec le ministre du ministère qui a déféré le projet au Bureau. Toutefois, les décisions finales sont suspendues jusqu'à l'examen approfondi de la demande par l'O.N.E. ou tout autre organisme de réglementation approprié.

Moyennant certaines conditions particulières, l'Office national de l'énergie peut ne pas insister sur la tenue d'une audience publique et l'approbation du gouvernement. Ainsi l'Office peut autoriser les exportations de petite envergure, c'est-à-dire des exportations inférieures à 50 MW ou à 250 GWh/année. Il peut également émettre un certificat de service public pour la construction d'une ligne internationale de transport d'une puissance inférieure à 5 MW. En cas d'urgence, l'O.N.E. peut, de son propre chef, autoriser l'exportation d'énergie à des clients américains dont les services sont interconnectés à des réseaux canadiens.

Dans des circonstances normales, il faut douze mois à l'Office pour étudier une demande importante de certificat ou de permis. Une fois la demande approuvée, l'Office prépare un "Décret du conseil" qui est présenté au ministre de l'Énergie, des Mines et des Ressources. Le ministre peut, à sa discrétion, recommander le projet au Gouverneur en conseil. La décision de l'Office n'a pas force exécutoire tant que le Gouverneur en conseil n'a pas accordé son approbation.

L'Office délivre des permis distincts pour l'exportation d'énergie interruptible, de puissance garantie, de puissance acheminée à court terme et de puissance acheminée par un intermédiaire. Chaque permis fixe la quantité maximale d'énergie autorisée, normalement par année ou sur une période de douze mois consécutifs. Le permis établit également un prix minimum. Le détenteur du permis peut toutefois négocier à l'intérieur de ces conditions générales.

L'Office doit approuver toute modification ultérieure apportée au prix ou aux conditions de l'entente.

3.2 Compétence gouvernementale - les États-Unis

Aux Etats-Unis, les gouvernements fédéral et étatiques se partagent la compétence en matière de réglementation de l'industrie de l'électricité. Le gouvernement fédéral a compétence sur les exportations d'électricité effectuées par les services privés et sur la construction d'installations de transport à la frontière internationale.

Il existe cependant un chevauchement des compétences en matière de réglementation de la construction des lignes internationales de transport d'énergie. Les commissions des services publics de chaque état ont compétence sur les installations de production et de transport d'électricité implantées sur leur territoire. Comme le gouvernement fédéral n'a compétence que sur les installations franchissant une frontière, les états exercent la plus grande autorité en ce qui concerne le tracé des lignes, leur design et leur exploitation. Dans certains cas, l'emplacement des installations de transport est sujet à l'approbation municipale.

La construction d'installations internationales de transport est autorisée par un permis présidentiel. Même si le *Department of Energy* a le pouvoir d'étudier les demandes de permis, des renseignements peuvent aussi être fournis par l'Agence de protection de l'environnement (Environmental Protection Agency) et le Corps des ingénieurs (Corps of Engineers). Toutes les demandes doivent être approuvées par le secrétaire à la Défense et le secrétaire d'État.

Le ministère de l'Intérieur doit, pour sa part, approuver toute demande de passage d'une ligne de transport sur des terres du gouvernement fédéral, dans des réserves indiennes ou dans des habitats fauniques particuliers.

3.2.1 L'octroi des permis aux États-Unis

Contrairement à l'Office national de l'énergie, le *Department of Energy* n'a pas fixé de conditions précises pour l'évaluation des demandes de permis; les demandes sont étudiées isolément.

Chaque demande est évaluée en fonction de renseignements fournis sur le plan environnemental, technique et économique. Le *Department of Energy* prend également en considération l'information obtenue au cours d'audiences publiques et les mémoires subséquents présentés par les requérants. L'étude d'un dossier demande environ 6 mois, et peut prendre de 18 à 24 mois s'il faut effectuer une évaluation des répercussions environnementales.

4. Coordination internationale

De vastes réseaux d'interconnexions ont été mis en place au Canada, aux États-Unis et entre les deux pays, dans une large mesure à cause des économies engendrées par la possibilité d'acheminer l'énergie des grandes centrales, y compris les centrales éloignées, vers de nombreux centres de distribution. Si les interconnexions ont permis d'améliorer la fiabilité des réseaux, par contre certaines pannes ont pris un grand nombre d'abonnés au dépourvu en même temps, à preuve la rupture de l'interconnexion entre New York et l'Ontario survenue en 1965.

Les travaux de planification et de coordination réalisés à l'échelle de l'industrie électrique tout entière par le *North American Electric Reliability Council (NERC)* permettent de croire qu'à l'avenir les grandes pannes pourront être évitées ou leur durée abrégée.

Le NERC a été mis sur pied en 1968, par des participants volontaires. Son objectif est d'accroître la fiabilité et l'efficacité des réseaux de transport de grandes quantités d'énergie en Amérique du Nord. Neuf conseils régionaux sont représentés au sein du NERC. Les membres individuels sont des représentants des grandes entreprises d'électricité. Au nombre des membres canadiens figurent la B.C. Hydro, l'Hydro-Ontario, la Manitoba Hydro, la Commission d'énergie électrique du Nouveau-Brunswick, l'Hydro-Québec, la TransAlta Utilities et la Saskatchewan Power. La constitution du NERC autorise un représentant de l'O.N.E. et un représentant du *Department of Energy* des États-Unis à participer aux réunions à titre d'observateurs.

5. Avantages du commerce de l'électricité

Les échanges d'électricité entre le Canada et les États-Unis procurent une vaste gamme d'avantages techniques, économiques et sociaux aux services publics et aux abonnés des deux pays. Les avantages de l'accroissement des transactions internationales ont été énumérés dans "L'Étude sur les échanges d'électricité Canada États-Unis"[5].

- *Fiabilité et partage des réserves*: Les ententes contractuelles destinées à assure un appui mutuel entre les services publics en cas d'urgence peuvent être utilisées soit pour améliorer la fiabilité de l'ensemble du réseau, soit pour réduire la marge des réserves nécessaires pour chaque activité.
- *Complémentarité des charges*: Lorsque deux services publics d'électricité, situés dans des régions adjacentes ou relativement rapprochées, enregistrent des charges de pointe à différentes périodes de l'année, ils peuvent être desservis par une capacité de production installée réduite si les charges des réseaux sont combinées. Ce "partage" de la production procure des avantages économiques aux deux réseaux.
- *Vente d'énergie excédentaire*: L'énergie non nécessaire à un réseau de production au moment de sa disponibilité peut être vendue à un marché secondaire (par exemple à un autre service public) ou (dans le cas de l'énergie hydro-électrique) emmagasinée dans les réservoirs d'un autre service public. Les sources énergétiques susceptibles de fournir une quantité d'énergie supérieure aux besoins courants sont les centrales hydro-électriques au fil de l'eau et les réservoirs de stockage de l'eau les années où le niveau de l'eau est élevé (lorsque l'eau serait autrement gaspillée). Dans un proche avenir, on y incluera peut-être les génératrices solaires et éoliennes et l'énergie marémotrice. La possiblilité de recourir à cette énergie excédentaire permettra de réduire les coûts d'exploitation et d'économiser les combustibles fossiles.
- *Interversions économiques*: Il y a interversion économique lorsque le coût marginal* du kilowattheure produit par un réseau fournisseur est inférieur à celui du réseau acheteur. Des unités génératrices efficaces ou des variations dans le coût des combustibles peuvent permettre à un réseau donné de fournir de l'énergie à un coût inférieur à celui de l'énergie générée par le réseau acheteur avec son propre équipement.
- *Économies à l'échelle de la puissance des unités*: Les unités plus puissantes ont des coûts plus faibles pour leur production d'électricité que les petites unités. Cependant, lorsqu'un service public n'est pas en mesure d'installer une unité génératrice de taille optimale, des transactions internationales permettent aux services publics d'électricité de planifier conjointement les projets d'expansion de leurs réseaux et d'installer des unités plus puissantes. De telles ententes sont à l'avantage des deux services publics sur le plan financier.
- *Programmation coordonnée des opérations*: En coordonnant les programmes d'entretien des unités de production, les services publics voient à l'exploitation efficace de leurs entreprises.
- Recours à technologies complémentaires: De nombreuses techniques ou technologies de production sont complémentaires. Jusqu'à présent, la coopération entre les centrales hydro-électriques et les centrales thermiques a été des plus fructueuses. Les années où l'eau est basse, les unités hydro-électriques assurent la capacité requise en période de pointe tandis que les unités thermiques fournissent l'énergie de base. Les années où il y a suffisamment d'eau, la production hydro-électrique remplace la production thermique plus coûteuse.

* Le coût marginal correspond au coût du prochain kilowattheure disponible produit par le réseau fournisseur.

- *Réduction de la dépendance vis-à-vis du pétrole*: Des opérations plus efficaces, l'utilisation accrue de centrales alimentées au charbon et les ressources renouvelables permettent de réduire l'utilisation du pétrole dans la production d'électricité. Ces améliorations ont été rendues possibles grâce à l'augmentation des échanges d'électricité d'un service public a l'autre. Et toute réduction de la dépendance vis-à-vis du pétrole réduit le niveau des importations.
- *Économie locale*: La construction d'installations de production et de transport pour le marché à l'exportation est source d'emplois et augmente l'assiette fiscale dans la zone exportatrice.

Les exportations d'électricité sont également à l'avantage du Canada sur les plans suivants:

- *Recettes*: Les recettes d'exportation permettent de réduire le coût du service offert aux abonnés de l'entreprise exportatrice. Les recettes peuvent compenser des hausses de tarifs ou servir au financement de nouvelles installations, en réduisant par le fait même la dépendance sur des fonds de l'extérieur.

[5] "Étude sur les échanges d'électricité Canada/États-Unis", mai 1979.